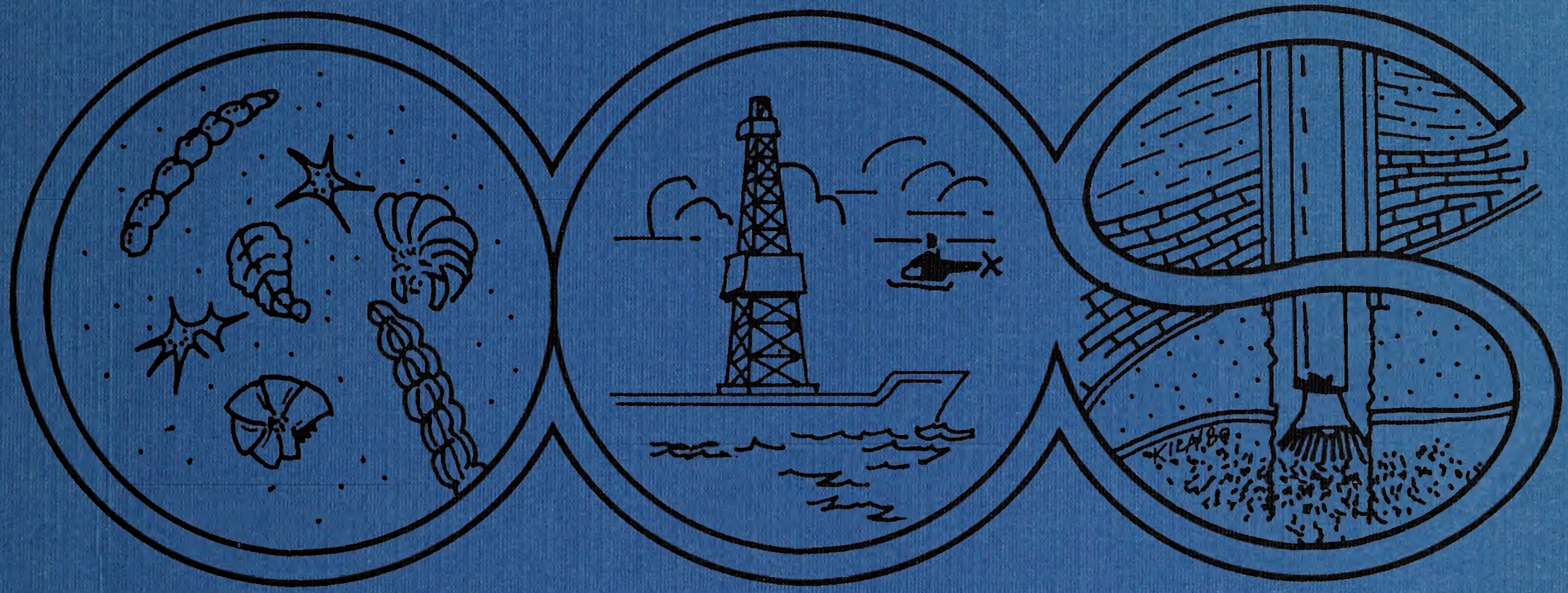
COMPILATION OF REGULATIONS RELATED TO MINERAL RESOURCE ACTIVITIES ON THE OUTER CONTINENTAL SHELF



U.S. DEPARTMENT OF THE INTERIOR

U.S. GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT

JANUARY 1981

VOLUME I OF II

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Information for ordering additional copies of this compilation from the National Technical Information Service (NTIS) is enclosed in the back of each Volume.

50272-101

REPORT DOCUMENTATION PAGE	1. REPORT NO.	2.	3. Recipient's Accession No. PB81-151524

4. Title and Subtitle
Compilation of Regulations Related to Mineral Resource Activities on the Outer Continental Shelf - Volume I

5. Report Date
January 1981

6.

7. Author(s) A. Dewey Acuff, Kenneth W. Blake, Ronald L. Brignac, and Debra F. Dretar

8. Performing Organization Rept. No.

9. Performing Organization Name and Address
Conservation Division, U.S. Geological Survey,
National Center, Reston, Va. 22092

10. Project/Task/Work Unit No.

11. Contract(C) or Grant(G) No.
(C)
(G)

12. Sponsoring Organization Name and Address
Conservation Division, U.S. Geological Survey,
National Center, Reston, Va. 22092

13. Type of Report & Period Covered

14.

15. Supplementary Notes
Compilation of Regulations Related to Mineral Resource Activities on the Outer Continental Shelf - Volume II - PB81-15132

16. Abstract (Limit: 200 words)

This document, in two volumes, is a compilation of Federal regulations which directly or indirectly relate to the OCS mineral resource program responsibilities of the Department of the Interior. Source documents used for this compilation were the Code of Federal Regulations and the Federal Register. Forty-nine regulations (CFR Parts), as amended, are included. Preambles to regulations, as published in the Federal Register, have been included on a selective basis. Twenty-four preambles are included. References to amending regulations, as published in the Federal Register, are included in the introductory paragraph preceding each regulation and at the end of each section All amendments through December 31, 1980, have been included and referenced

17. Document Analysis a. Descriptors

b. Identifiers/Open-Ended Terms

c. COSATI Field/Group

18. Availability Statement:	19. Security Class (This Report)	21. No. of Pages
Release unlimited	Unclassified	400
	20. Security Class (This Page)	22. Price
	Unclassified	

(See ANSI-Z39.18) *See Instructions on Reverse* OPTIONAL FORM 272 (4-77) (Formerly NTIS-35) Department of Commerce

ACKNOWLEDGMENTS

Special thanks are extended to Isabella G. Hopkins, Librarian, U.S. Geological Survey Metairie, Louisiana, who offered valuable suggestions and worked many hours in obtaining source materials; J. Lawrence Courtney and Marie S. Sunseri, U.S. Geological Survey, Metairie, Louisiana, who, with the assistance of others, provided extensive editing services; and to William J. Martin, Director, U.S. Navy Publications and Printing Service Office, New Orleans, Louisiana, who provided detailed assistance concerning the processing, printing and publication of this compilation.

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VOLUMES I and II

I. INTRODUCTION

The Secretary of the Interior has been designated by law to manage and regulate many of the activities which relate to the leasing, exploration, development, and production of mineral resources of the Outer Continental Shelf (OCS). Most of the Department's responsibilities involving these activities have been delegated to the Geological Survey and the Bureau of Land Management.

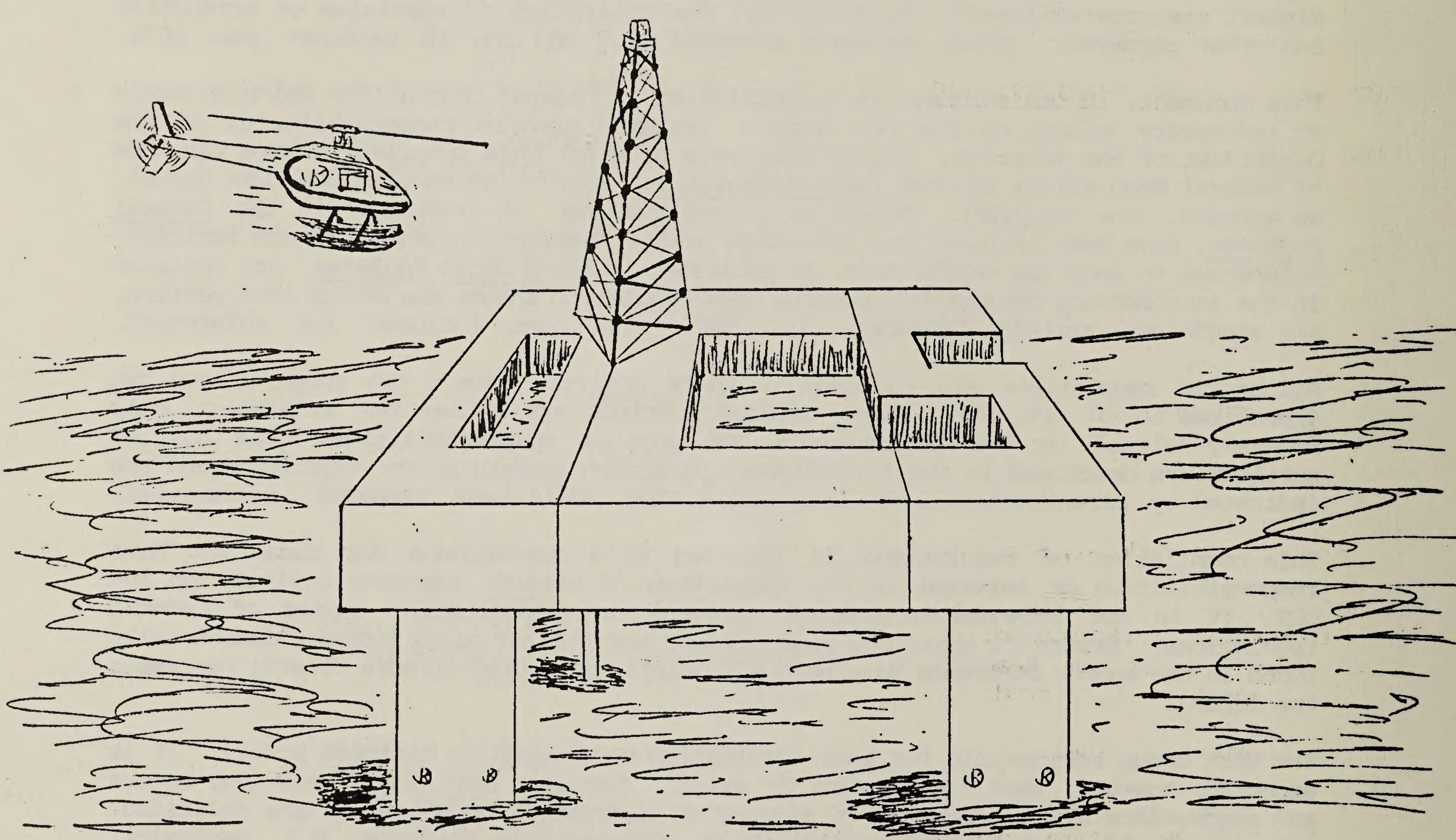
The Bureau of Land Management has primary responsibility, with resource evaluation and other technical assistance from the Geological Survey, for the leasing of OCS mineral resources and the permitting of pipeline rights-of-way across the OCS. The Geological Survey has primary responsibility for the regulation of activities conducted for the exploration, development, and production of OCS mineral resources, including various mineral resource evaluation functions and the collection of royalties on production and other payments. These payments exceeded $1.5 billion in calendar year 1979.

This document, in two volumes, is a compilation of Federal regulations which directly or indirectly relate to the OCS mineral resource program responsibilities of the Department of the Interior. Source documents used for this compilation were the Code of Federal Regulations and the Federal Register. Forty-nine regulations (CFR Parts), as amended, are included. Preambles to regulations, as published in the Federal Register, have been included on a selective basis. Twenty-four preambles are included. References to amending regulations, as published in the Federal Register, are included in the introductory paragraph preceding each regulation and at the end of each section. All amendments through December 31, 1980, have been included and referenced.

All of the regulations are included in their entirety except two subparts and two appendices in 10 CFR 212. These omitted portions are either not related or only remotely related to the Department's OCS program responsibilities. The omitted portions are described in the introductory paragraph preceding the regulation and are indicated by parenthetical notations where they would have appeared in the text.

This compilation of regulations is intended as a convenience for those who have responsibilities or interest in the regulation of mineral resource activity on the OCS. It is not intended to present official or authoritative copies of Federal regulations. Errors in spelling, punctuation, and similar minor errors, occasionally found in the source documents have been editorially corrected to more clearly represent the intent.

The Work Group responsible for this compilation endeavored to minimize errors. It is expected, however, that some errors do exist. Comments from users regarding errors and suggestions for improvement of revised or additional compilations are solicited. Comments should be forwarded to the Chief, Conservation Division, U.S. Geological Survey, National Center (MS 610), Reston, Va. 22092.



A. 10 CFR 212, Mandatory Petroleum Price Regulations, Title 10 CFR, revised as of January 1, 1980, amended by: 45 FR 1583-84, January 7, 1980; 45 FR 9534, February 12, 1980; 45 FR 14844, March 7, 1980; 45 FR 21208-09, April 1, 1980; 45 FR 29551-52, May 2, 1980; 45 FR 36052, May 29, 1980; 45 FR 38039, June 6, 1980; 45 FR 39241, June 10, 1980; 45 FR 40107, June 13, 1980; 45 FR 41903, June 23, 1980; 45 FR 46760, July 10, 1980; 45 FR 47407, July 14, 1980; 45 FR 47624, July 15, 1980; 45 FR 71766, October 30, 1980; 45 FR 72630, November 3, 1980; 45 FR 78593, November 25, 1980; 45 FR 80483, December 5, 1980; and 45 FR 81009, December 8, 1980.

Subparts E, Refiners, and L, Resales of Crude Oil; Appendix A to Part 212-Standby Regulations, and Appendix B to Part 212-Special Rule No. 2, are omitted, except in the Table of Contents.

PART 212—MANDATORY PETROLEUM PRICE REGULATIONS

AUTHORITY: Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, E.O. 11748, 38 FR 33577; Economic Stabilization Act of 1970, as amended, Pub. L. 92-210, 85 Stat. 743; Pub. L. 93-28, 87 Stat. 27; E.O. 11748, 38 FR 33575; Cost of Living Council Order Number 47, FR 24, unless otherwise noted.

SOURCE: 39 FR 1949, Jan. 15, 1974, unless otherwise noted.

NOMENCLATURE CHANGES: 40 FR 40820, Sept. 4, 1975; 41 FR 36184, Aug. 26, 1976.

EDITORIAL NOTE: Regulations in this part are affected by a document published at 44 FR 37938, June 29, 1979. See the redesignation table appearing in the Finding Aids section of this volume.

Subpart A--General

§ 212.1 Scope.

(a) This part sets forth the price rules for firms engaged in the production and sale of covered products and the leasing of real property used in the retailing of gasoline, effective 11:59 p.m., e.s.t., January 14, 1974.

(b) The price rules of the Economic Stabilization Program, Title 6 of the Code of Federal Regulations, remain effective until 11:59 p.m., d.s.t., January 14, 1974, with respect to sales of covered products and the leasing of real property used in the retailing of gasoline.

(c) Price renegotiation provisions in price or rent contracts which depend for their operation upon the modification or termination of Economic Stabilization Program, were previously declared to be inoperative as unreasonably inconsistent with the goals of the Economic Stabilization Program. Such renegotiation provisions continue to be inoperative as unreasonably inconsistent with the goals of both the Economic Stabilization Program and the Department of Energy. This part shall not operate to permit:

(1) A retroactive increase in prices or rents for goods or services sold or leased while those prices or rents were subject to past or present provisions of 6 CFR, or

(2) A prospective increase in prices or rents under the terms of a contract subject to a decision and order issued at any time pursuant to Title 6, except to the extent consistent with such decision and order.

(d) Any report required to be filed with the Cost of Living Council under 6 CFR, or any rule, order or regulation of the Council in effect on January 14, 1973, for any reporting period which ended on or before that date and which was not filed by that date, shall be filed with the Cost of Living Council in the form and within the time in which it would have been filed pursuant to Title 6. Forms required to be completed and placed among the records of a firm on a quarterly basis pursuant to Title 6 for any quarter which ended prior to January 14, 1974, shall be completed and filed among the firm's records in the form and within the time in which it would have been required to be so filed pursuant to Title 6.

[39 FR 1949, Jan. 15, 1974, as amended at 39 FR 6532, Feb. 20, 1974; 40 FR 2795, Jan. 16, 1975]

§ 212.2 Applicability.

This part applies to each sale or purchase of a covered product in the United States except as provided in Subpart C.

[40 FR 60037, Dec. 31, 1975]

§ 212.10 General rules.

(a) No firm (including an individual) may charge a price for any covered product which exceeds the maximum price at which that product is permitted to be sold to the class of purchaser concerned under this part.

(b) No firm (including an individual) may

knowingly pay a price for any covered product which exceeds the maximum price at which that product is permitted to be sold to the class of purchaser concerned under this part.

(c) Paragraph (b) of this section does not apply to the purchase of a covered product under circumstances of economic or other coercion in which the purchaser, because of its need for that product, had no reasonable alternative but to pay the unlawful price and he promptly reports the payment of the unlawful price to the Department of Energy.

[40 FR 60037, Dec. 31, 1975]

Subpart B—Definitions

§ 212.31 Definitions.

For purposes of this part--

"Aviation fuel (kerosene-type)" means a relatively low freezing point distillate of the kerosene type and includes all kerosene products with an average gravity of 40.7° API and 10 to 90 percent distillation temperatures of 390° F. to 470° F. covered by ASTM D1655 specifications, and including JP-5 and other fuels meeting military specifications (MIL-T-5624G Amend. 1).

"Aviation fuel (naphtha-type)" means all fuels in the heavy naphtha boiling range with an average gravity of 52.8° API and 10 to 90 percent distillation temperatures of 210° F. to 420° F., including JP-4 and other fuels meeting military specifications MIL-F-5624 and MIL-T-5624G, used for turbojet and turboprop aircraft engines, primarily by the military.

"Aviation fuels" means aviation fuel (kerosene-type), aviation fuel (naphtha-type), and aviation gasoline.

"Aviation gasoline" means all of the various grades of aviation gasoline as defined in ASTM D910-70.

"Aviation jet fuel" means aviation fuel (kerosene-type) and aviation fuel (naphtha-type).

"Benzene" means an aromatic hydrocarbon whose chemical composition is predominantly C_6H_6.

"Butane" means a hydrocarbon whose chemical composition is predominantly C_4H_{10}, whether recovered from natural gas or crude oil.

"Ceiling price" means the ceiling price determined pursuant to § 212.73 with respect to domestic crude oil.

"Class of purchaser" means purchasers to whom a person has charged a comparable price for comparable property or service pursuant to customary price differentials between those purchasers and other purchasers.

"Consignee agent" means a firm which distributes covered products to purchasers pursuant to a contractual arrangement with a refiner under which the refiner retains title to the covered products and specifies the prices to be paid by the purchaser and under which the refiner pays the consignee agent a commission based on the volume of covered products distributed by the consignee agent.

"Covered products" means crude oil, gasoline, natural gas liquids and propane. A blend of two or more particular covered products is considered to be that particular covered product constituting the major portion of the blend. A blend of one or more covered products with one or more non-petroleum-based products is a covered product if the covered product or products constitutes more than 50 percent by volume of the blend, and is that covered product which is the most predominant by volume in the blend.

"Crude oil" means a mixture of hydrocarbons that existed in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. "Crude oil" includes condensate recovered in associated or non-associatd production by mechanical separators, whether located on the lease, at central field facilities, or at the inlet side of a gas processing plant.

"Customary price differential" includes a price distinction based on a discount, allowance, add-on, premium, and an extra based on a difference in volume, grade, quality, or location or type of purchaser, or a term or condition of sale or delivery.

"Domestic crude oil" means crude oil produced in the United States or from the "outer continental shelf" as defined in 43 U.S.C. 1331.

"Ethane" means a hydrocarbon whose chemical composition is C_2H_6.

"Firm" means any association, company, corporation, estate, individual, joint-venture, partnership, or sole proprietorship or any other entity however organized including charitable, educational, or other eleemosynary institutions, and the Federal government including corporations, departments, Federal agencies, and other instrumentalities, and State and local governments. The DOE may, in regulations and forms issued in this part, treat as a firm: (1) A parent and the consolidated and unconsolidated entities (if any) which it directly or indirectly controls, (2) a parent and its consolidated entities, (3) an unconsolidated entity, or (4) any part of a firm.

"Fiscal quarter" means the fiscal quarter of the firm to which a regulation containing the term applies.

"Fiscal year" means the fiscal year of the firm to which a regulation containing the term applies. It is a consecutive 12-month period constituting an accounting year.

"Fixed base operator" means a firm which maintains facilities at an airport for the purpose of (1) engaging in the retail sale of aviation fuels primarily to purchasers other than (a) scheduled or supplemental air carriers

certificated by the Civil Aeronautics Board pursuant to 49 U.S.C. 1371 or (b) the Department of Defense; and (2) performing one or more of the following general aviation activities: (a) Aircraft maintenance, servicing, parking, tie-down, storage and other aircraft services; (b) baggage and cargo handling and other passenger/freight services; and (c) maintenance of avionics equipment and systems.

"Gas oil" means all liquid petroleum distillate having a viscosity intermediate between that of kerosene and lubricating oil.

"Gasoline" means all of the various grades, other than aviation gasoline, of refined petroleum naphtha which, by its composition, is suitable for use as a carburant in internal combustion engines.

"General refinery products" means all covered products other than No. 2 oils, aviation jet fuel, gasoline, and crude oil.

"Greases" means all lubricating greases which are solid to semifluid products comprising a dispersion of a thickening agent in a liquid lubricant.

"Hexane" means a hydrocarbon whose chemical composition is predominantly C_6H_{14}.

"Item" means a product sold or offered for sale to a class of purchaser.

"Kerosene" means all refined petroleum distillate suitable for use as an illuminant when burned in a wick lamp.

"Lubricant base oil stocks" means all refined petroleum products that are primary components used in the compounding and blending of lubricants and greases, including but not limited to bright stocks, solvent neutrals, coastal oils, pale oils and red oils.

"Lubricants" means all grades of lubricating oils that have been blended with the necessary lubricating oil composition in a form that is designed to be used for lubricating purposes wherein said lubricating oils are comprised of greater than ten (10) percent by weight of refined petroleum products.

"Manufacturing" means the trade or business of making, fabricating, or assembling a product or commodity by manual labor or machinery for sale and also includes the mining of natural deposits, the production or refining of oil from wells, and the refining of ores.

"Middle distillates means Nos. 1 and 2 heating oils, Nos. 1-D and 2-D diesel fuels, kerosene, and aviation fuels.

"Naphthas" means all petroleum fractions, not otherwise defined as aviation fuels, gasoline, or special naphthas, made up predominantly of hydrocarbons whose boiling point falls within the temperature range of 85° to 430° F.

"Natural gas" means natural gas as defined by the Federal Power Commission.

"Natural gas liquids" means a mixed hydrocarbon stream containing, in whole or in substantial part, mixtures of ethane, butane (isobutane and normal butane), propane or natural gasoline.

"Natural gasoline" means all liquid hydrocarbon mixtures containing substantial quantities of pentanes and heavier hydrocarbons, that have been extracted from natural gas.

"No. 1 heating oil" means heating oil grade No. 1 as defined in American Society for Testing and Materials (ASTM) D396-71.

"No. 1-D diesel fuel" means diesel fuel grade No. 1 as defined in American Society for Testing and Materials (ASTM) D975-71.

"No. 2 heating oil" means heating oil grade No. 2 as defined in American Society for Testing and Materials (ASTM) D396-71.

"No. 2 oils" means No. 2 heating oil and No. 2-D diesel fuel.

"No. 2-D diesel fuel" means diesel fuel grade No. 2 as defined in American Society for Testing and Materials (ASTM) D975-71.

"No. 4 fuel oil" means fuel oil grade No. 4, as defined in American Society for Testing and Materials (ASTM) D396-71.

"No. 4-D diesel fuel" means diesel fuel grade No. 4 as defined in American Society for Testing and Materials (ASTM) D975-71.

"Octane number" means the octane number derived from the sum of Research (R) and Motor (M) octane numbers divided by two (R+M)/2. The research octane (R) and motor octane number (M) shall be described in the American Society for Testing and Materials (ASTM) "Standard Specifications for Gasoline" D439-70, and subsequent revisions, and ASTM Test Methods D 2699 and D 2700.

"Other finished products" means all finished products, not otherwise defined as a particular covered product, such as, but not limited to, petrolatum, absorption oils, ramjet fuel, petroleum rocket fuels, and other finished products except finished petro-chemicals.

"Parent" means a firm which is not directly or indirectly controlled by another firm.

"Parent and its consolidated entities," means a parent and those firms, if any, directly or indirectly controlled by the parent which are consolidated with the parent for purposes of financial statements prepared in accordance with generally accepted accounting principles. An individual shall be deemed to control a firm which is directly or indirectly controlled by him or by his father, mother, spouse, children or grandchildren.

"Posted price" means a written statement of crude oil prices circulated publicly among sellers and buyers of crude oil in a particular field in accordance with historic practices, and generally known by sellers and buyers within the field.

"Price" means any consideration for the sale of any property or services and includes commissions, dues, fees, margins, rates, charges, tariffs, fares, or premiums, regardless of form.

"Price increase" means an increase in the unit price of an item or a decrease in the

quality or quantity of substantially the same item.

"Producer" means a firm or that part of a firm which produces crude oil or natural gas, or any firm which owns crude oil or natural gas when it is produced.

"Product" means a unit of personal property offered for sale to another person.

"Propane" means a hydrocarbon whose chemical composition is predominantly C_3H_8, whether recovered from natural gas or crude oil.

"Refiner" means a firm (other than a reseller or retailer) or that part of such a firm which refines covered products or blends and substantially changes covered products, or refines liquid hydrocarbons from oil and gas field gases, or recovers liquefied petroleum gases incident to petroleum refining and sells those products to resellers, retailers, reseller-retailers or ultimate consumers. "Refiner" includes any owner of covered products which contracts to have those covered products refined and then sells the refined covered products to resellers, retailers, reseller-retailers or ultimate consumers.

"Reseller" means a firm (other than a refiner or retailer) or that part of such a firm which carries on the trade or business of purchasing covered products, and reselling them without substantially changing their form to purchasers other than ultimate consumers.

"Reseller-retailer" means a firm (other than a refiner) or that part of such a firm which carries on the functions of both a reseller and retailer.

"Residual fuel oil" means No. 4 fuel oil, No. 4-D diesel fuel, those fuel oils commonly known as ASTM Grades No. 5 and No. 6 fuel oils, heavy diesel, Navy Special, Bunker C and all other fuel oils which have a fifty percent boiling point over 700° F. in the ASTM D86 standard distillation test.

"Retail sales" means sales of covered products to ultimate consumers.

"Retailer" means a firm (other than a refiner or reseller) or that part of such a firm which carries on the trade or business of purchasing covered products and reselling them to ultimate consumers without substantially changing their form.

"Service" includes any work or activities performed by a firm for a person, other than in an employment relationship, and also includes professional work or activities of any kind and work or activities performed by membership organizations for which dues are charged, and the leasing or licensing of property to another person.

"Service activities" means the trade or business of selling or making available services, including professional service organizations, non-profit organizations, governments, and government agencies or instrumentalities which carry on those activities.

"Special naphthas (solvents)" means all finished products within the gasoline range, not otherwise defined as aviation fuels or gasoline, specially refined to specified flash point and boiling range, for use as paint thinners, cleaners, solvents, etc.

"State and local governments" means the several States, the District of Columbia, and the territories and possessions of the United States other than the Panama Canal Zone, a municipality or other political subdivision, authority, commission, board, district, public corporation or other agency or instrumentality of the several States, the District of Columbia, and the territories and possessions of the United States other than the Panama Canal Zone and any board, commission, agency or other instrumentality of a local government.

"Toluene" means an aromatic hydrocarbon whose chemical composition is predominantly C_7H_8.

"Transaction" means an arms-length sale between unrelated persons which are not members of a controlled group (as defined in 26 U.S.C. 1563(a)) and is considered to occur at the time and place when a binding contract is entered into between the parties.

"Unconsolidated entity" means a firm directly or indirectly controlled by a parent but not consolidated with the parent for purposes of financial statements prepared in accordance with generally accepted accounting principles. An unconsolidated entity includes any firm consolidated with the unconsolidated entity for purposes of financial statements prepared in accordance with generally accepted accounting principles. An individual shall be deemed to control a firm which is directly or indirectly controlled by him or by his father, mother, spouse, children or grandchildren.

"Unfinished oils" means all oils requiring further refining i.e., any operation except mechanical blending or use as an additive.

"Unrelated person" means a person other than a person described in section 267(b) of the Internal Revenue Code of 1954, as amended.

"Xylene" means a mixed stream of aromatic hydrocarbons whose chemical composition is predominantly C_8H_{10} containing, in whole or in substantial part, the isomers para-xylene, metaxylene, and ortho-xylene.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[39 FR 1949, Jan. 15, 1974, as amended at 39 FR 6532, Feb. 20, 1974, 39 FR 7582, Feb. 27, 1974;

39 FR 12011, 12013, Apr. 2, 1974; 39 FR 12354, Apr. 5, 1974; 39 FR 13258, Apr. 12, 1974; 39 FR 24358, July 2, 1974; 39 FR 42369, Dec. 5, 1974; 39 FR 44411, Dec. 24, 1974; 40 FR 2796, Jan. 16, 1975; 40 FR 10445, Mar. 6, 1975; 40 FR 40820, Sept. 4, 1975; 40 FR 57442, Dec. 10, 1975; 40 FR 60038, Dec. 31, 1975; 41 FR 5117, Feb. 4, 1976; 41 FR 9088, Mar. 3, 1976; 41 FR 13898, Apr. 1, 1976; 41 FR 15333, Apr. 12, 1976; 41 FR 30098, July 22, 1976; 41 FR 34008, Aug. 12, 1976; 41 FR 40453, Sept. 20, 1976; 42 FR 4421, Jan. 25, 1977; 42 FR 5036, Jan. 27, 1977; 44 FR 7073, Feb. 5, 1979; 44 FR 70120, Dec. 6, 1979]

Subpart C—Exemptions

§ 212.51 General.

Prices charged with regard to the items and sales described in this subpart are exempt from the price rules prescribed in this part.

[41 FR 9088, Mar. 3, 1976]

§ 212.52 Sales by Federal, State or local governments.

The prices charged for any sale of a covered product by any Federal department, agency, or other instrumentality, including any wholly owned Government corporation as defined in the Government Corporation Control Act of 1945, as amended, and by State and local governments are subject to the price regulations of this part, except that, with respect to deliveries of crude oil made on or before February 21, 1974, a State or local government may charge a bonus price per barrel of crude oil provided that such bonus price was stipulated in existing contracts and provided further that the balance of the price per barrel shall be based upon lawful prices charged for domestic crude oil subject to price regulations in effect at the time such deliveries were made, and not upon prices charged for crude oil that was exempt from price regulation.

[41 FR 4939, Feb. 3, 1976]

§ 212.53 Exports and imports.

(a) The prices charged for export sales, including sales to a domestic purchaser which certifies the product is for export, are exempt.

(b) The prices charged for imports, but only the first sale into U.S. commerce, are exempt. For purposes of this subparagraph, any sale of imported crude oil, not already entered into the United States customs territory, to the Government for storage in the Strategic Petroleum Reserve will be deemed a first sale into U.S. commerce.

(c) Non-bonded aviation fuel uplifted in the United States for international flights departing from the United States shall not be considered as export for the purposes of this part.

(E.O. 11730, 38 FR 19345)

[39 FR 1949, Jan. 15, 1974, as amended at 39 FR 12997, Apr. 10, 1974; 41 FR 30323, July 23, 1976; 45 FR 71766, Oct. 30, 1980]

§ 212.54 Stripper well crude oil.

(a) Prices charged in the first sale of crude oil (excluding condensate recovered in non-associated production), produced and sold from any stripper well property are exempt from the provisions of this part.

(b) Prices charged in the first sale of imputed stripper well crude oil, as defined in § 212.75 of this part, produced and sold from any unitized property are exempt from the provisions of this part.

(c) Definitions. "Average daily productions" means the qualified maximum total production of crude oil (excluding condensate recovered in non-associated production) produced from a property, divided by a number equal to the number of days in the 12-month qualifying period times the number of wells that produced crude oil (excluding condensate recovered in non-associated production) from that property in that 12-month qualifying period. To qualify as maximum total production, each well on the property must have been maintained at the maximum feasible rate of production throughout the 12-month qualifying period and in accordance with recognized conservation practices, and not significantly curtailed by reason of mechanical failure or other disruption in production.

"First sale" means the first transfer for value by the producer or royalty owner. With respect to transfers between affiliated entities, the "first sale" shall be imputed to occur as if in arms-length transactions.

"Stripper well property" means a "property" whose average daily production of crude oil (excluding condensate recovered in non-associated production) per well did not exceed 10 barrels per day during and preceding consecutive 12-month period beginning after December 31, 1972.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[41 FR 48323, Nov. 3, 1976, as amended at 43 FR 33697, Aug. 1, 1978]

§ 212.55 Naval Petroleum Reserves crude oil.

The price charged in the first sale of U.S.-owned crude oil pursuant to the provisions of the Naval Petroleum Reserves Production Act of 1976 (Pub. L. 94-258) is exempt from the provisions of this part.

[41 FR 48323, Nov. 3, 1976]

§ 212.56 General refinery products.

(a) The following general refinery products are exempt from the provisions of this part: Aviation gasoline, benzene, gas oil, greases, hexane, kerosene, lubricant base oil stocks, lubricants, naphthas, No. 1 heating oil, No. 1-D diesel fuel, residual fuel oil, special naphthas (solvents), toluene, unfinished oils, xylene, and other finished products.

(b) The following general refinery products are not exempt from the provisions of this part: Butane, natural gas liquids, natural gasoline, and propane.

[44 FR 7073, Feb. 5, 1979]

NOTE: The provisions of this section may be affected by Standby Regulation 212-2. Standby Regulation 212-2 appears in Appendix A to Part 212. For the convenience of the user, a table listing all Standby Regulations and sections affected appears in the Finding Aids section of this volume.

§ 212.57 No. 2 oils.

The prices charged for No. 2 oils are exempt.

[41 FR 44152, Oct. 7, 1976]

NOTE: The provisions of this section may be affected by Standby Regulation 212-2. Standby Regulation 212-2 appears in Appendix A to Part 212. For the convenience of the user, a table listing all Standby Regulations and sections affected appears in the Finding Aids section of this volume.

§ 212.58 Aviation jet fuel.

The sales of aviation jet fuel are exempt from the provisions of this part.

[44 FR 7073, Feb. 5, 1979]

§ 212.59 Heavy crude oil.

(a) Prices charged in the first sale of heavy crude oil are exempt from the provisions of this Part.

(b) Heavy crude oil means all crude oil produced from any property during a period when the property qualified as a heavy crude oil property.

(c) For the period August 17, 1979, through December 20, 1979, heavy crude oil property means any property from which the crude oil produced and sold during the base month had a weighted average gravity of 16.0° API or less, corrected to 60° Fahrenheit.

(d) On and after December 21, 1979, heavy crude oil property means any property from which the crude oil produced and sold during the base month had a weighted average gravity of 20.0° API or less, corrected to 60° Fahrenheit.

(e) For purposes of this section, the base month for a particular property is the last month prior to July 1979 in which crude oil was produced and sold from that property.

(f) For purposes of this section, the weighted average gravity for the crude oil produced and sold from a particular property shall be the gravity determinations used in connection with the first sale of crude oil from that property during the base month; provided that, with respect to a property to which a diluent had been injected into the well bores thereon during the base month, the weighted average gravity shall be based on the last gravity test on crude oil produced from that property prior to July 1979 and prior to the first injection of a diluent.

(g) For purposes of this section, the crude oil produced from a property does not include any diluent injected into that property.

(h) Any unitized property that includes only properties that prior to inclusion within the unit qualified as heavy crude oil properties shall qualify as a heavy crude oil property.

[45 FR 21208, Apr. 1, 1980; 45 FR 78593, Nov. 25, 1980]

§ 212.60 Butane.

The prices charged for butane are exempt from the provisions of this part.

[44 FR 70121, Dec. 6, 1979]

§ 212.61 Natural gasoline.

The prices charged for natural gasoline are exempt from the provisions of this part.

[44 FR 70121, Dec. 6, 1979]

§ 212.62 Butane and natural gasoline components of natural gas liquids.

The prices charged for the butane and natural gasoline components of natural gas liquids are exempt from the provisions of this part.

[44 FR 70121, Dec. 6, 1979]

Subpart D--Producers of Crude Petroleum

§ 212.71 Applicability.

This subpart applies to each first sale of domestic crude oil except as provided in Subpart C of this part.

[41 FR 48323, Nov. 3, 1976]

§ 212.72 Definitions.

"Average completion depth" means for each particular marginal property the sum of all completion depths for all wells that produced crude oil from the property concerned during calendar year 1978, divided by the number of such wells during that 12-month period.

"Average daily production" means for each particular marginal property the qualified maximum total production of crude oil (excluding condensate recovered in non-associated production) produced from a property, divided by 365 times the number of wells that produced crude oil (excluding condensate recovered in non-associated production) from that property during calendar year 1978. To qualify as maximum total production, each well on the property must have been maintained at the maximum feasible rate of production throughout that 12-month period and in accordance with recognized conservation practices, and not significantly curtailed by reason of mechanical failure or other disruption in production.

"Base production control level" means: (a) With respect to months ending prior to February 1, 1976:

(1) If crude oil was produced and sold from the property concerned in every month of 1972, the total number of barrels of domestic crude oil produced and sold from that property in the same month of 1972;

(2) If crude oil was not produced and sold from the property concerned in every month of 1972, the total number of barrels of crude oil produced and sold from that property in 1972, divided by 12;

(b) With respect to months commencing after January 31, 1976, except as provided in § 212.76(a), either:

(1) The total number of barrels of old crude oil produced and sold from the property concerned during calendar year 1975, divided by 365, multiplied by the number of days during the month in 1975 which corresponds to the month concerned; or

(2) If the producer elects to certify crude oil sales for 1972 in accordance with § 212.131(a)(2), the total number of barrels of crude oil produced and sold from the property concerned during calendar year 1972, divided by 366, multiplied by the number of days during the month in 1972 which corresponds to the month concerned;

(c) With respect to months commencing after May 31, 1979, except as provided in § 212.76, for properties other than marginal properties, either:

(1) The total number of barrels of old crude oil produced and sold from the property concerned during the six-month period ending March 31, 1979, divided by 182, multiplied by the number of days during the month in 1978 which corresponds to the month concerned; or

(2) If the producer elects to certify crude oil sales for 1975 in accordance with § 212.131(a)(2), the total number of barrels of old crude oil produced and sold from the property concerned during calendar year 1975, divided by 365, multiplied by the number of days during the month in 1975 which corresponds to the month concerned; or

(3) If the producer elects to certify crude oil sales for 1972 in accordance with § 212.131(a)(2), the total number of barrels of crude oil produced and sold from the property concerned during calendar year 1972, divided by 366, multiplied by the number of days during the month in 1972 which corresponds to the month concerned;

(d) With respect to marginal properties, the base production control level equals (1) with respect to months commencing after May 31, 1979, 20 percent of the total number of barrels of old crude oil produced and sold from the property concerned during calendar year 1978, divided by 365, multiplied by the number of days during the month in 1978 which corresponds to the month concerned; (2) for the months commencing after December 31, 1979, zero.

"Completion depth" means the depth from which crude oil was produced, as reported to the applicable state regulatory authority. Where such reports are not required to be made, completion depth means the depth in feet measured from ground level, or from the top of the surface casing, along the bore hole to the base of perforations from which a well produces crude oil; with respect to a well which has been completed "open hole," completion depth means the lesser of (a) the depth to the base of the reservoir, or (b) the "plugged-back" depth. Provided that where no official state regulatory depth report has been made, completion depth must be documented with an affidavit executed by a registered petroleum engineer.

"Current cumulative deficiency" means: (a) For months prior to February 1, 1976, the total number of barrels by which production and sale of crude oil was less than the base production control level, for all months in which production and sale of crude oil was less than the base production control level subsequent to the first month in which new crude oil was produced and sold, minus the total number of

barrels of domestic crude oil produced and sold in each prior month which was in excess of the base production control level for that month, but which was not classified as new crude oil because of this requirement to reduce the amount of new crude oil in each month by the amount of the current cumulative deficiency;

(b) For months commencing after January 31, 1976, the total number of barrels by which production and sale of crude oil has been less than the base production control level subsequent to the first month (after February 1, 1976) in which new crude oil was produced and sold, minus the total number of barrels of domestic crude oil produced and sold in each month after February 1, 1976, which was in excess of the base production control level for that month, but which was not classified as new crude oil because of this requirement to reduce the amount of new crude oil in each month by the amount of the current cumulative deficiency;

(c) For months commencing after May 31, 1979, at the option of the producer either:

(1) The total number of barrels by which production and sale of crude oil has been less than the base production control level subsequent to the first month (after June 1, 1979) in which new crude oil was produced and sold, minus the total number of barrels of domestic crude oil produced and sold in each prior month after June 1, 1979, which was in excess of the base production control level for that month, but which was not classified as new crude oil because of this requirement to reduce the amount of new crude oil in each month by the amount of the current cumulative deficiency; or

(2) The total number of barrels by which production and sale of crude oil has been less than the base production control level subsequent to any two-month period in which the total production and sale of crude oil from the property concerned exceeds the sum of the property's base production control levels for that two-month period, minus the total number of barrels of domestic crude oil produced and sold in each prior month after June 1, 1979, which was in excess of the base production control level for that month, but which was not classified as new crude oil because of this requirement to reduce the amount of new crude oil in each month by the amount of the current cumulative deficiency. A producer may not elect this option (2) for any property from which new crude oil was produced and sold as new crude oil in any month which begins after May 31, 1979.

"First sale" means the first transfer for value by the producer or royalty owner. With respect to transfers between affiliated entities, the "first sale" shall be imputed to occur as if in arms-length transactions.

"Marginal property" means a property whose average daily production of crude oil (excluding condensate recovered in non-associated production) per well during calendar year 1978 did not exceed the number of barrels shown in the following table for the corresponding average completion depth:

Average completion depth in feet	Barrels per day
2,000 or more but less than 4,000...	20 or less.
4,000 or more but less than 6,000...	25 or less.
6,000 or more but less than 8,000...	30 or less.
8,000 or more but less than 10,000..	35 or less.
Each additional 2,000 foot interval.	An additional 5 barrels.

"Market level new crude oil" means, with respect to a particular property during a particular month, the product of the market level factor for that month and the volume of new crude oil produced and sold from that property during that month. The market level factor for January 1980 shall be four and six-tenths percent (4.6%) and shall be increased by four and six-tenths percent (4.6%) in each succeeding month.

"New crude oil" means, with respect to a specific property: (a) For months prior to February 1, 1976, the total number of barrels of domestic crude oil produced and sold in a specific month, less (1) the base production control level for that month, and less (2) the current cumulative deficiency;

(b) For months commencing after January 31, 1976, the total number of barrels of domestic crude oil produced and sold in a specific month, less (1) the property's base production control level for that month and less (2) the current cumulative deficiency since February 1, 1976;

(c) For months commencing after May 31, 1979, the total number of barrels of domestic crude oil produced and sold in a specific month, less (1) the base production control level for that month, and less (2) the current cumulative deficiency since June 1, 1979; and

(d) Shall not in any period include any number of barrels not certified as new crude oil pursuant to the provisions of § 212.131(a)(1) within the consecutive two-month period immediately succeeding the month in which the crude oil is produced and sold, except where such recertification is explicitly required or permitted by DOE order, interpretation or ruling.

"Old crude oil" means: (a) Prior to February 1, 1976, the total number of barrels of crude oil produced and sold from a property in a specific month, less the total number of barrels of new crude oil for that property in that

month, and less the total number of barrels of released crude oil for that property in that month;

(b) Effective February 1, 1976, the total number of barrels of crude oil produced and sold from a property in a specifc month, less the total number of barrels of new crude oil for that property in that month.

"Produced and sold" means, for purposes of subparts C and D of this part, the production and first sale, transfer of custody (including transfers between affiliated entities), or any other disposition for which value or benefit is directly or indirectly received by the producer or royalty owner, including the disposal or consumption of crude oil in any manner on the property from which it is produced. Crude oil is deemed to be produced and sold at the time that the produced crude oil leaves the property or is disposed of or consumed on the property, whichever occurs first.

"Property" means the right to produce domestic crude oil, which arises from a lease or from a fee interest. A producer may treat as a separate property each separate and distinct producing reservoir subject to the same right to produce crude oil, provided that such reservoir is recognized by the appropriate governmental regulatory authority as a producing formation that is separate and distinct from, and not in communication with, any other producing formation.

"Released crude oil" means an amount of crude oil produced from a property in a particular month prior to February 1, 1976, which is equal to the total number of barrels of new crude oil produced and sold from that property in that month. The amount of released crude oil for a property in a particular month shall not exceed the base production control level for that property in that month, and shall not include any number of barrels, not certified as such pursuant to the provisions of § 212.131(a)(1) within the consecutive two-month period immediately succeeding the month in which the crude oil is produced and sold, except where such recertification is explicitly required or permitted by DOE order, interpretation, or ruling.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275; E.O. 11790, 39 FR 23185, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[40 FR 31747, July 29, 1975, as amended at 41 FR 4940, Feb. 3, 1976; 41 FR 15574, Apr. 13, 1976; 41 FR 36184, Aug. 26, 1976; 44 FR 25167, Apr. 27, 1979; 44 FR 37938, June 29, 1979; 44 FR 66186, Nov. 19, 1979; 45 FR 47407, July 14, 1980; 45 FR 78593, Nov. 25, 1980]

§ 212.73 Lower-tier ceiling price rule.

(a) Rule. Except as provided in § 212.74 with respect to new crude oil; except as provided in § 212.75 for certain crude oil produced from unitized properties; except as provided in § 212.78 for incremental crude oil produced from qualified tertiary enhanced recovery projects and for tertiary incentive crude oil; except as provided in § 212.79 for newly discovered crude oil; and except as provided in Subpart C of this Part for exempt crude oil, no producer may charge a price higher than the lower-tier ceiling price for any first sale of domestic crude oil.

(b) Lower-tier ceiling price determination other than in Alaska and California. The lower-tier ceiling price for a particular grade of domestic crude oil in a particular field other than in Alaska or California is the sum of: (1) The highest posted price at 6 a.m., local time, May 15, 1973, for transactions in that grade of crude oil in that field, or if there was no posted price in that field for that grade of domestic crude oil, the related price for that grade of domestic crude oil which is most similar in kind and quality in the nearest field for which prices were posted; plus (2) $1.35 per barrel.

(c) Lower-tier ceiling price determination in Alaska and California. In Alaska and California, the lower-tier ceiling price for a particular grade of domestic crude oil in a particular field is the sum of: (1) The highest posted price at 6 a.m., local time, May 15, 1973, for transactions in that grade of crude oil in that field, or if there was no posted price in that field for that grade of domestic crude oil, the related price for that grade of domestic crude oil which is most familiar in kind and quality in the nearest field for which prices were posted; plus (2) $1.35 per barrel; plus (3) 2 cents for each degree API gravity between 34 degrees API gravity and 40 degrees API gravity that the domestic crude oil being offered for sale is below 40 degrees API gravity, plus (4) 3 cents for each degree API gravity that the domestic crude oil being offered for sale is below 34 degrees API gravity.

(Emergency Petroleum Allocation Act of 1973, 15 U.S.C. 751 et seq., Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, 15 U.S.C. 787 et seq., Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, and Pub L. 95-91; Energy Policy and Conservation Act, 42 U.S.C. 6201 et seq., Pub. L. 94-163, as

amended, Pub. L. 94-385, and Pub. L. 95-70; Department of Energy Organizaion Act, 42 U.S.C. 7101 et seq., Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[41 FR 48324, 48325, Nov. 3, 1976, as amended at 44 FR 51152, Aug. 30, 1979]

§ 212.74 Upper-tier ceiling price rule.

(a) Notwithstanding the provisions of § 212. 73(a), a producer may in any month charge a price not to exceed the upper-tier ceiling price in first sales of new crude oil, except that first sales of market level new crude oil are not subject to the ceiling price limitations of this subpart.

(b) Upper-tier ceiling price determination. The upper-tier ceiling price for a particular grade of domestic crude oil in a particular field is (1) the highest posted price on September 30, 1975, for transactions in that grade of crude oil in that field in September 1975, or if there was no posted price in that field for that grade of domestic crude oil, the related price for that grade of domestic crude oil which is most similar in kind and quality in the nearest field for which prices were posted; less (2) $1.32 per barrel.

(c) Retroactive increase in price. No producer may charge or accept a retroactive increase in price for crude oil, other than crude oil which is exempt from this Subpart pursuant to § 212.54 and is sold on September 1, 1976, or thereafter, or crude oil which is exempt from this Subpart pursuant to § 212.55 and is sold on April 5, 1976, or thereafter. Retroactive increase in price means any price charged or offered after the close of the calendar month in excess of the highest price prevailing for that grade of crude oil, in first sales between the producer and the purchaser of the domestic crude oil, during the calendar month in which it was produced and sold.

(d) Notwithstanding the provisions of § 212. 73(a) and of paragraph (a) of this section, with respect to crude oil sold pursuant to the provisions of Part 391 of this chapter, a producer may charge a per barrel price that exceeds the ceiling price otherwise permitted under this subpart by no more than one half of one percent of the per barrel market price of such crude oil computed pursuant to the provisions of Part 391 of this chapter.

(e) Notwithstanding the provisions of § 212. 73(a) and of paragraph (a) of this section, with respect to crude oil produced from a property or portion thereof for which DOE has issued an order under Subpart D of 10 CFR Part 205 or a decision on an appeal of such an order under Subpart H of 10 CFR Part 205 that specifies the percentage of such crude oil that may be sold at the lower-tier, upper-tier or other prices by or for the benefit of one or more owners thereof, the same percentages of crude oil, as specified in the order, may be sold at lower-tier, upper-tier or other prices by or for the benefit of any other owner of an interest in such crude oil or an interest in the property from which such crude oil is produced.

(Secs. 4 and 8, Pub. L. 93-159, 87 Stat. 629, 633 (15 U.S.C. 753 and 757); Pub. L. 93-511, 88 Stat. 1608; sec. 2, Pub. L. 94-99, 89 Stat. 481; sec. 1, Pub. L. 94-133, 89 Stat. 694; secs. 401(a), 401(b)(1)-(3), 402(a), 403(a) and 451, Pub. L. 94-163, 89 Stat. 941, 946, 948; secs. 121 and 122, Pub. L. 94-385, 90 Stat. 1132, 1133, secs. 301 and 644, Pub. L. 95-91 Stat. 577, 599, (42 U.S.C. 7151 and 7254); E.O. 12009, 42 FR 46267)

[41 FR 4940, Feb. 3, 1976, as amended at 41 FR 48324, Nov. 3, 1976; 44 FR 66188, Nov. 19, 1979; 45 FR 9534, Feb. 12, 1980]

§ 212.75 Crude oil produced and sold from unitized properties.

(a) Rule. With respect to each unitized property, a producer shall, as of the effective date of unitization, establish a unit base production control level.

(b) Definitions. For purposes of this section--

"Current unit cumulative deficiency" means (1) for months prior to June 1, 1979, the total number of barrels by which production and sale of crude oil from the unitized property was less than the unit base production control level subsequent to the first month (following the establishment of a unit base production control level for that unitized property) in which any crude oil produced and sold from that unit was eligible to be classified as actual new crude oil (without regard to whether the amount of actual new crude oil was exceeded by the amount of imputed new crude), minus the total number of barrels of domestic crude oil produced and sold in each prior month from that unitized property (following the establishment of a unit base production control level for that unitized property) which was in excess of the unit base production control level for that month, but which was not eligible to be classified as actual new crude oil because of this requirement to reduce the amount of actual new crude oil in each month by the amount of the current unit cumulative deficiency;

(2) For months commencing after May 31, 1979, at the option of the producer either (i) the total number of barrels by which production and sale of crude oil from the unitized property has been less than the unit base production control level subsequent to the first month (after June 1, 1979) in which new crude oil was

produced and sold, minus the total number of barrels of domestic crude oil produced and sold from the unitized property in each prior month after June 1, 1979, which was in excess of the unit base production control level for that month, but which was not classified as new crude oil because of this requirement to reduce the amount of new crude oil in each month by the amount of the current unit cumulative deficiency; or

(ii) The total number of barrels by which production and sale of crude oil from the unitized property has been less than the unit base production control level subsequent to any two-month period in which the total production and sale of crude oil from the unitized property concerned exceeds the sum of the property's unit base production control levels for that two-month period, minus the total number of barrels of domestic crude oil produced and sold in each prior month after June 1, 1979, which was in excess of the unit base production which was not classified as new crude oil because of this requirement to reduce the amount of new crude oil in each month by the amount of the current unit cumulative deficiency. A producer may not elect the option described in this paragraph (ii) for any unitized property from which new crude oil was produced and sold as new crude oil in any month which begins after May 31, 1979.

"Imputed heavy crude oil" means, with respect to a unitized property for which a unit base production control level was established after August 16, 1979, in a particular month, either (1) a number of barrels of crude oil equal to the total number of barrels of crude oil produced and sold in that particular month from all properties that constitute that unitized property, multiplied by the total number of barrels of crude oil produced during the 12-month period immediately preceding the establishment of a unit base production control level for that unitized property from all properties that constitute the unitized property which qualified as heavy oil properties prior to inclusion within the unit, divided by the sum of (i) the total number of barrels of crude oil produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property from all properties other than heavy crude oil properties that constitute the unitized property, plus (ii) the total number of barrels of crude oil produced during that period from all crude oil properties that constitute the unitized property which qualified as heavy crude oil properties prior to inclusion within the unit, or (2) a number of barrels of crude oil equal to the total number of barrels of crude oil produced during the 12-month period preceding the establishment of a unit base production control level for the unitized property from all properties that constitute the unitized property which qualified as heavy crude oil properties prior to inclusion within the unit, divided by the number of days in that 12-month period, and multiplied by the number of days in that particular month, whichever is greater. For purposes of this definition, the 12-month period prior to the inclusion of a heavy crude oil property within a unit may be reduced to the number of days in the months in that period in which heavy crude oil was produced and sold from that property.

"Imputed newly discovered crude oil" means, with respect to a unitized property for which a unit base production control level was established after January 1, 1979, in a particular month, either (1) a number of barrels of crude oil equal to the total number of barrels of crude oil produced and sold in that particular month from all properties that constitute the unitized property, multiplied by the total number of barrels of crude oil produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property from all newly discovered crude oil properties that constitute the unitized property, divided by the sum of (i) the total number of barrels of crude oil produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property from all properties other than newly discovered crude oil properties that constitute the unitized property, plus (ii) the total number of barrels of crude oil produced during that period from all newly discovered crude oil properties that constitute the unitized property; or (2) a number of barrels of crude oil equal to the total number of barrels of crude oil produced and sold during the 12-month period preceding the establishment of a unit base production control level for the unitized property from all newly discovered crude oil properties that constitute the unitized property, divided by the number of days in that 12-month period, and multiplied by the number of days in that particular month, whichever is greater.

For purposes of this definition, the 12-month period prior to the inclusion of a newly discovered crude oil property within a unit may be reduced to the number of days in the months in that period in which newly discovered crude oil was produced and sold from that property.

"Imputed stripper well crude oil" means, (1) with respect to a unitized property for which a unit base production control level was established prior to August 1, 1977, in a particular month, a number of barrels of crude oil equal to the total number of barrels of crude oil (excluding condensate recovered in non-associated production) produced during the 12-month period immediately preceding the establishment of a unit base production control

level for the unitized property from all stripper well properties (qualified as such as of the establishment of a unit base production control level for the unitized property) that constitute the unitized property, divided by the number of days in that 12-month period, and multiplied by the number of days in that particular month; (2) with respect to a unitized property for which a unit base production control level was established on or after August 1, 1977, in a particular month, either (i) a number of barrels of crude oil equal to the total number of barrels of crude oil produced and sold in that particular month from all properties that constitute the unitized property, multiplied by the total number of barrels of crude oil (excluding condensate recovered in non-associated production) produced during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property from all stripper well properties (qualified as such as of the establishment of a unit base production control level) that constitute the unitized property, divided by the sum of (A) the total number of barrels of crude oil produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property from all non-stripper well properties that constitute the unitized property, plus (B) the total number of barrels of crude oil produced during that period from all stripper well properties that constitute the unitized property, or (ii) a number of barrels of crude oil equal to the total number of barrels of crude oil (excluding condensate recovered in non-associated production) produced during the 12-month period preceding the establishment of a unit base production control level for the unitized property from all stripper well properties (qualified as such as of the establishment of a unit base production control level of the unitized property) that constitute the unitized property, divided by the number of days in that 12-month period, and multiplied by the number of days in that particular month, whichever is greater.

"New crude oil" means, in a particular month, (1) with respect to a unitized property for which a unit base production control level was established prior to August 1, 1977, either (i) actual new crude oil, which is the total number of barrels of crude oil produced and sold in that month from all properties that constitute the unitized property, less (A) the unit base production control level, and less (B) the current cumulative deficiency; or (ii) imputed new crude oil, which is a number of barrels of crude oil equal to the total number of barrels of new crude oil produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property, from all properties that constitute the unitized property, divided by the number of days in that 12-month period, and multiplied by the number of days in the particular month whichever number is greater; (2) with respect to a unitized property for which a unit base production control level was established on or after August 1, 1977, either (i) actual new crude oil, which is the total number of barrels of crude oil produced and sold in a specific month from all properties that constitute the unitized property, less (A) the unit base production control level, and less (B) the total number of barrels of imputed stripper well crude oil, if any, for the particular month, and less (C) the total number of barrels of imputed newly discovered crude oil, if any, for the particular month, and less (D) the current unit cumulative deficiency; or (ii) imputed new crude oil, which is a number of barrels of crude oil equal to the total number of barrels of new crude oil produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property, from all properties that constitute the unitized property, divided by the number of days in the 12-month period immediately preceding the establishment of a unit base production control level, multiplied by the number of days in the particular month, whichever number is greater.

"Old crude oil" means, in a particular month, the total number of barrels of crude oil produced and sold in that month from all properties that constitute the unitized property, less (1) the total number of barrels of new crude oil produced and sold from the unitized property in that month, and less (2) the total number of barrels of imputed stripper well crude oil produced and sold from the unitized property in that month, and less (3) the total number of barrels of imputed newly discovered crude oil produced and sold from the unitized property in that month.

"Significant alteration in producing patterns" means the occurrence of either (1) the application of extraneous energy sources by the injection of liquids or gases into the reservoir, or (2) the increase of production allowable for any property that constitutes the unitized property.

"Unit base production control level" means, in a particular month, (1) with respect to a unitized property for which the volume of imputed stripper well production is determined pursuant to the provisions of paragraph (1), or paragraph (2)(ii) of the definition of "imputed stripper well crude oil," (i) the total number of barrels of old crude oil, as defined in § 212.72, produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property from all properties that constitute the unitized property,

divided by the number of days in that 12-month period, and multiplied by the number of days in the particular month; plus (ii) the total number of barrels of crude oil produced during that 12-month period from all stripper well properties that constitute the unitized property, divided by the number of days in that 12-month period, and multiplied by the number of days in the particular month; plus (iii) the total number of barrels of crude oil produced during that 12-month period from all newly discovered crude oil properties that constitute the unitized property, divided by the number of days in that 12-month period, and multiplied by the number of days in the particular month; (2) with respect to a unitized property for which the volume of imputed stripper well crude oil is determined pursuant to the provisions of paragraph (2)(i) of the definition "imputed stripper well crude oil," the total number of barrels of old crude oil, as defined in § 212.72, produced and sold during the 12-month period immediately preceding the establishment of a unit base production control level for the unitized property from all properties that constitute the unitized property, divided by the number of days in that 12-month period, and multiplied by the number of days in the particular month.

"Unitized property" means the right to produce crude oil that arises from a bona fide unitization agreement approved by the applicable governmental regulatory authority (or ERA).

(c) Notwithstanding the provisions of paragraph (a) of this section, a producer shall not be required to establish a unit base production control level for a particular unitized property, provided that the producer has (pursuant to the provisions of 10 CFR Part 205, Subpart G) certified to ERA its intention to determine volumes of lower-tier, upper-tier, newly discovered, and stripper well property crude oil separately for all properties that constitute the unitized property, and provided further that the unitized property has not sustained a significant alteration in producing patterns.

(d) Except as provided in paragraphs (e), (f), and (g) of this section with respect to new crude oil, imputed stripper well crude oil, and imputed newly discovered crude oil, no producer of crude oil from a unitized property may charge a price higher than the lower-tier ceiling price (as determined pursuant to §§ 212.73 and 212.77 of this part) for the first sale of domestic crude oil produced and sold from the unitized property.

(e) Notwithstanding the provisions of paragraph (d) of this section, a producer of crude oil from a unitized property may, in any month, charge a price not to exceed the upper-tier ceiling price (as determined pursuant to §§ 212.74 and 212.77 of this part) in first sales of new crude oil produced and sold from the unitized property.

(f) Notwithstanding the provisions of paragraph (d) of this section, the prices charged by a producer of crude oil from a unitized property in first sales of imputed newly discovered crude oil are not subject to the ceiling price limitations of this subpart.

(g) Notwithstanding the provisions of paragraph (d) of this section, the prices charged in any month by a producer of crude oil from a unitized property in first sales of imputed stripper well crude oil are exempt.

(h) Notwithstanding the provisions of the definition of "unit base production control level" in paragraph (b) of this section, with respect to any unitized property for which a unit base production control level was established prior to June 1, 1979, a producer may, effective June 1, 1979, select as the unit base production control level, the total number of barrels of old crude oil produced and sold during the six month period ending March 31, 1979, from all properties that constitute the unitized property, divided by 182, times the number of days during the month in 1978 which corresponds to the month concerned. The selection of a unit base production control level pursuant to this paragraph (h) does not constitute the "establishment of a unit base production control level" for any purpose under this part.

(i) The provisions of this section shall apply to each first sale of crude oil from a unitized property.

(Emergency Petroleum Allocation Act of 1973, 15 U.S.C. 751 _et seq._, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, 15 U.S.C. 787 _et seq._, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, and Pub. L. 95-91; Energy Policy and Conservation Act, 42 U.S.C. 6201 _et seq._, Pub. L. 94-163, as amended, Pub. L. 94-385, and Pub. L. 95-70; Department of Energy Organization Act, 42 U.S.C. 7101 _et seq._, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[44 FR 25830, May 2, 1979; 45 FR 78594, Nov. 25, 1980]

§ 212.76 Adjustments to base production control levels.

(a) Eligibility--(1) With respect to each property for which a base production control level is not determined pursuant to the provisions of paragraph (c)(1) of the definition of "base production control level" in § 212.72, and from which no new crude oil is produced in any month in the five-month period ending June 30, 1976, after June 30, 1976, a producer may adjust the base production control level for the property concerned for each month during

that six-month period in accordance with paragraph (b) of this section.

(2) With respect to each property for which a base production control level is not determined pursuant to the provisions of paragraph (c)(1) of the definition of "base production control level" in § 212.72, and from which new crude oil is produced in any month in the five-month period ending June 30, 1976, a producer may adjust the base production control levels applicable thereto in accordance with paragraph (b) of this section, commencing with the six-month semi-annual period immediately following a six-month semi-annual period ending subsequent to June 30, 1976, in which the total amount of crude oil produced and sold from the property concerned was less than the sum of the base production control levels for that period.

(3)(i) Effective June 1, 1979, with respect to any property for which the base production control level is determined pursuant to the provisions of paragraph (c)(1) of the defintion of "base production control level" in § 212.72, and with respect to any unitized property for which the unit base production control level is selected pursuant to the provisions of paragraph (g) in § 212.75, a producer may adjust the base production control level for the property concerned in each month only in accordance with the following formula—

ABPCL=[1-(N)(.015)] (BPCL)

Where:

ABPCL=The adjusted base production control level or the adjusted unit base production control level for the month concerned.
BPCL=The base production control level or the unit base production control level for the month concerned.
N=The number of months, including the month concerned, since December 31, 1978.

(ii) Effective January 1, 1980, with respect to any property a producer may adjust the base production control level or unit base production control level in accordance with the following formula—

ABPCL=[(.82)-(N)(.03)] (BPCL)

Where:

ABPCL=The adjusted base production control level or the adjusted unit base production control level for the month concerned.
BPCL=The base production control level or the unit base production control level for the month concerned.
N=The number of months, including the month concerned, since December 31, 1979.

(b) Rule. The base production control level for properties which qualify for an adjusted base production control level may be adjusted only in accordance with the following formulae:

(1) For the first six-month semi-annual period:

ABPCL=(1 - ARPD/1.33) (BPCL)

(2) For each subsequent six-month semi-annual period:

ABPCL=(1 - ARPD/2) (ABPCL')

Where:

ABPCL=The adjusted base production control level for the month concerned.
BPCL=The base production control level for the month concerned, computed under § 212.72 as revised effective February 1, 1976.
ABPCL'=The sum of the adjusted base production control levels for the immediately preceding six month period as computed pursuant to this section, divided by the number of days in that period and multiplied by the number of days in the month concerned.
ARPD=The annual rate of production decline applicable to the property concerned. The ARPD is determined by subtracting the total amount of crude oil produced and sold from the property concerned in 1975 from that property's total amount of crude oil produced and sold in 1972. The result, expressed as a percentage of the total amount of crude oil produced and sold from that property in 1972, is divided by three to obtain the ARPD.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[41 FR 15574, Apr. 13, 1976, as amended at 44 FR 25169, Apr. 27, 1979]

§ 212.77 Adjustments to ceiling prices.

(a) Rule. Notwithstanding any other provision of this Part, the DOE may, with respect to months commencing after February 29, 1976, provide for adjustments to the ceiling prices established under §§ 212.73 and 212.74 to take into account the impact of inflation, provide a production incentive, and otherwise to achieve compliance with the Act. The adjustment to reflect the impact of inflation shall be measured by the first revision of the quarterly percentage change, seasonally adjusted at annu-

al rates, of the most recent price deflator for the gross national product, except that the combined effect of the adjustment to take into account the impact of inflation and to provide a production incentive may not result in an increase in the maximum weighted average first sale price (as defined in section 8(a) of the Act) in excess of 10 percent per year.

(b) Procedures. In providing for price adjustments under paragraph (a) of this section, DOE shall from time to time issue a price adjustment schedule as an Appendix to this Subpart which shall specify the dollar amounts by which lower and upper tier ceiling prices may be adjusted pursuant to this section. Each price adjustment schedule shall be effective only until superseded by a subsequent price adjustment schedule. In subsequent price adjustment schedules DOE shall, as necessary, revise the lower and upper tier price ceilings applicable to the months remaining at the time the subsequent price adjustment schedule is issued, in order to reflect changes in the rate of inflation; to make compensating adjustments when the weighted average first sale price actually charged is found to have exceeded, or is found to have fallen short of, the maximum weighted average first sale price permitted under the Act; and otherwise to achieve compliance with the Act.

(c) Application of price adjustments. (1) Price adjustment schedules issued pursuant to paragraph (b) of this section shall, beginning with prices for September 1977, adjust the lower tier and the upper tier ceiling prices by not more than the amount necessary to reflect the impact of inflation on the weighted average first sale price for each tier.

(2) Notwithstanding paragraph (c)(1) of this section, DOE may issue price adjustment schedules pursuant to paragraph (b) of this section to (A) discontinue or restrict price adjustments or require reductions in ceiling prices to the extent deemed necessary by the DOE to achieve compliance with the Act, or (B) restore, in part or in full, to the upper tier ceiling price an amount not in excess of any reductions in such ceiling prices for months prior to September 1977.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185)

[41 FR 15574, Apr. 13, 1976, as amended at 41 FR 53334, Dec. 6, 1976; 42 FR 45289, Sept. 9, 1977]

§ 212.78 Tertiary incremental crude oil and tertiary incentive crude oil.

(a) Rule. (1) Incremental tertiary crude oil. Notwithstanding the provisions of § 212.73(a), first sales of incremental crude oil resulting from the implementation or expansion of a qualified tertiary enhanced recovery project are not subject to the ceiling price limitations of this subpart.

(2) Tertiary incentive crude oil. Notwithstanding the provisions of § 212.73(a), beginning January 1, 1980, first sales of crude oil by or for the behalf of a producer are not subject to the ceiling price limitations of this subpart, provided that the tertiary incentive revenue from such sales does not exceed the recoupable allowed expenses attributable to that producer.

(b) Applicability of paragraph (a)(1) to existing tertiary enhanced recovery projects. Incremental crude oil produced from a tertiary enhanced recovery project, or expansion thereof, which was initiated prior to the date on which a producer has satisfied the requirements of either paragraph (d)(1) or (e)(1) of this section with respect to that project, may qualify for pricing in accordance with paragraph (a)(1) of this section only if:

(1) The producer affirms that he intends to discontinue the project (or the particular high-cost phase of the project) in the absence of permission to price production therefrom in accordance with paragraph (a)(1) of this section, because continuation of the project (or the particular high-cost phase) would be uneconomic at the otherwise applicable ceiling price;

(2) There has been a material change of circumstances since the time that the project was initiated or expanded; and

(3) The project is certified pursuant to paragraph (e)(1) of this section. For the purposes of determining eligibility for certification, an existing project shall be examined prospectively, on the basis of the circumstances existing at the time such certification is sought.

(c) Definitions. For purposes of this section—

"Alkaline (or caustic) flooding" means an augmented waterflooding technique in which the water is made chemically basic as a result of the addition of alkali metals. The concentration and size of the alkaline slug must be at least 500 ppm-PV for the alkaline concentration multiplied by the pore volume of the alkaline slug.

"Allowed expense" means seventy-five percent of an environmental expense or seventy-five percent of an engineering and laboratory expense or seventy-five percent of an expense listed either in the appendix to this section or in a order issued pursuant to either paragraph (e)(2) or (e)(3) of this section; provided that, an

allowed expense may not be based on an expense incurred and paid prior to August 22, 1979. No more than one million dollars or twenty-five percent, whichever is less, of the total amount of allowed expenses with respect to a particular project may be based on engineering and laboratory expenses. The allowed expenses of a particular project shall be attributable to the qualified producer(s) with respect to that project. Where there is more than one qualified producer, the qualified producers shall allocate these expenses among themselves in whatever manner they determine. With respect to a particular property, the total amount of allowed expenses may not exceed twenty million dollars.

"Certifying authority" means the Administrator, Economic Regulatory Administration, Department of Energy, or any officer of the Department of Energy to whom the Administrator has delegated such functions.

"Conventional steam drive injection" means the continuous injection of at least 50 quality steam (surface conditions) into one set of wells (injection wells) to effect oil displacements toward and production from a second set of wells (production wells). The process may include the prior, concurrent, alternating or subsequent injection of water, solvents and/or other fluids into any portion of the reservoir to assist in recovery and conformance.

"Cyclic steam injection" means the alternating injection of at least 50 quality steam (surface conditions) and production of oil with condensed steam from the same well or wells.

"Engineering and laboratory expense" means an expense relating to field-laboratory quality control equipment, reservoir and geologic evaluation as required for optimum process design, engineering plans, facility design, and laboratory/field process optimization (tracer, pressure transient, injectant quality, etc.).

"Enhanced heavy oil recovery technique" means any technique for the recovery of crude oil with a gravity less than 16° API.

"Environmental expenses" means those expenses that are incurred in connection with a particular project to the extent that those expenses are necessary to comply with federal or state environmental regulations applicable to that project.

"Immiscible gas displacement" means injection of non-hydrocarbon gas into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained. The process may include the concurrent, alternating, or subsequent injection of water. The injected fluid measured at reservoir temperature and pressure must, with reasonable expectations, be more than 10 percent of the reservoir pore volume being served by the injection well or wells.

"In situ combustion" means combustion of oil in the reservoir, sustained by continuous air injection, to displace unburned oil toward producing wells provided that such combustion must be intended to continue until at least 15 percent of the reservoir volume being served by the injection well or wells has been burned. The process may include the concurrent, alternating, or subsequent injection of water.

"Incremental crude oil" means the amount of crude oil which is or will be produced as a result of the initiation or expansion of a qualified tertiary enhanced recovery project and which is in excess of the amount of crude oil ("non-incremental crude oil") which could have been produced from the property or project area through continued maximum feasible production from methods of production employed on the property prior to compliance with the requirements of paragraphs (d)(1) or (e)(1) of this section, whichever is applicable. As applied to an existing project within the meaning of paragraph (b) of this section, the term means the amount of crude oil which is or will be produced as a result of the continuation of the project and which is in excess of the amount of crude oil ("non-incremental crude oil") which could have been produced from the property or project area through continued maximum feasible production from methods of production (other than the tertiary method, or that phase of such methods, that would be discontinued in the absence of the incentive) employed on the property prior to receipt of the certification provided for in paragraph (e)(1) of this section. The actual amount of incremental crude oil in the case of any particular project shall be the amount produced from the property or project area during the period in question which is in excess of the amount of the non-incremental crude oil for that period as set forth in a certification by a producer pursuant to paragraph (d)(1) or as certified by the certifying authority pursuant to paragraph (e)(1) of this section; provided that, ERA may adjust the amount of non-incremental crude oil.

"Initiation" (of a project) means the start, on a regular basis, of a process that is intended to increase crude oil production.

"Microemulsion (or micellar/emulsion) flooding" means an augmented waterflooding technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells. A surfactant system normally includes a surfactant, hydrocarbon, cosurfactant, an electrolyte and water, and polymers for mobility control. The concentration and size of the micellar slug (not including the polymers and other non-surface active materials) must be more than 3000 ppm-PV for the combined active surfactant concentration and active cosurfactant concentration in the slug multiplied by the pore volume of the micellar slug.

"Miscible fluid displacement" means an oil displacement process in which fluid is injected

into an oil reservoir at pressure levels such that the injected fluid and reservoir oil are miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected fluid measured at reservoir temperature and pressure must, with reasonable expectations, be more than 10 percent of the reservoir pore volume being served by the injection well or wells. Gas cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique.

"Polymer augmented waterflooding" means augmented waterflooding in which polymers are injected with the water to improve areal and vertical sweep efficiency.

"Qualified producer" means, with respect to a particular project, a producer that possesses an interest in the property on which the project is located and contributes to the initiation or expansion of the project, provided that the producer has complied with the requirements of paragraphs (d)(2) or (e)(2) of this section, whichever is applicable.

"Qualified tertiary enhanced recovery project" means a project for the recovery of crude oil, to the extent that such project involves the application of an enhanced oil recovery technique; provided that, with respect to that project, a producer has complied with the requirements of either paragraphs (d)(1) or (e)(1) or this section, whichever is applicable.

"Recoupable allowed expenses" means, with respect to a particular producer, the allowed expenses that are attributable to that producer; provided that such expenses are incurred in arm's-length transactions and for fair market value and further provided that such expenses have been paid and reported pursuant to paragraph (h) of this section.

"Self-certifiable EOR technique" means any of the following enhanced oil recovery techniques: (a) miscible fluid displacement; (b) conventional steam drive injection; (c) unconventional steam drive injection; (d) microemulsion flooding; (e) in situ combustion; (f) polymer augmented waterflooding; (g) cyclic stream injection; (h) alkaline flooding; (i) immiscible non-hydrocarbon gas displacement; or (j) any enhanced heavy oil recovery technique.

"Self-certifiable tertiary project" means a a project for the recovery of crude oil to the extent that crude oil production from that project results from the initiation after September 30, 1979, of one of the following techniques: (a) unconventional steam drive injection, (b) in situ combustion, (c) microemulsion flooding, or (d) miscible fluid displacement.

"Tertiary incentive revenue" means, in the case of first sales of crude oil pursuant to the provisions of subsection [a][2], the excess of the market-clearing price over the otherwise applicable ceiling price less any <u>ad valorem</u>, severance or windfall profit tax attributable to this excess.

"Unconventional steam drive injection" means the continuous injection of at least 50 percent quality steam (at surface conditions) into one set of wells (injection wells) to effect oil displacement toward and production from a second set of wells (production wells). The process may include the prior, concurrent, alternating or subsequent injection of water, solvents, and/or other fluids into any portion of the reservoir to assist in recovery and conformance. This applies only to steam drive projects with an average depth greater than 2,500 ft. or steam drive projects which recover oil with a gravity less than 10° API.

"Well costs" means the non-capital expenses incurred in the reworking or reconditioning of wells to be used in the field project (as recognized by the Internal Revenue Service), the non-capital expenses incurred in the abandonment or reabandonment of wells (as necessary for proper engineering and environmental protection of the project) less any salvage value, and the intangible drilling costs of new production, injection and test/evaluation wells needed for the project (as recognized by the Internal Revenue Service).

(d) <u>Self-certification</u>. <u>(1) Qualified tertiary enhanced recovery projects</u>. With respect to a self-certifiable tertiary project, a producer shall certify to the certifying authority by certified mail that the project is a self-certifiable tertiary project. In this certification a producer must set forth, to the best of its ability, the amounts of non-incremental and incremental crude oil which will be produced in association with the project and the basis on which it determined these amounts.

(2) <u>Qualified producers</u>. A producer shall be considered a qualified producer with respect to a particular project if it certifies to the certifying authority by certified mail that that project employs a self-certifiable EOR technique.

(3) <u>Disallowance or modification of self-certifications</u>. A self-certification pursuant to either paragraphs (d)(1) or (d)(2) of this section shall be subject to disallowance or modification, at any time and either retroactively or prospectively or both, as and to the extent that the ERA determines to be appropriate:

(i) If the producer does not certify in good faith or implement the project in good faith; or

(ii) if certification was based on a material error or omission of fact of which the producer knew or should have known or to which the producer contributed; or

(iii) if the producer does not adhere to the

requirements of this section or any additional conditions and limitations which the ERA may prescribe.

(e) ERA certification. (1) Qualified tertiary enhanced recovery projects. A producer shall obtain final certification from the certifying authority that the project (or expansion) is a qualified tertiary enhanced recovery project and that the project would not be economic at the otherwise applicable ceiling prices. In addition, such producer shall obtain final certification of the amount of incremental and non-incremental crude oil which result from the implementation (or expansion) of such project. The amount of incremental and non-incremental crude oil shall be expressed in terms of both the total amount of incremental and non-incremental recovery over the life of the project (or such shorter period as the certifying authority determines to be appropriate) and in terms of incremental and non-incremental production estimates, commencing with the time that the project is estimated to begin producing incremental crude oil.

(2) Qualified producers. With respect to a project that does not employ a self-certifiable EOR technique, a producer shall obtain a final order from ERA that designates it as a qualified producer engaged in the initiation or expansion of a tertiary project that involves high levels of risk and of cost and that sets forth what the allowed expenses will be with respect to that project.

(3) Allowed expenses. With respect to a project that employs a self-certifiable EOR technique, a producer may request a final order from ERA that designates allowed expenses with respect to that property in addition to those based on environmental expenses, engineering and laboratory expenses, or expenses listed in the appendix to this section.

(4) General procedures. In order to receive an order pursuant to either paragraphs (e)(1), (e)(2), or (e)(3) of this section a producer shall submit a signed application to ERA. The general procedures of Subpart G of Part 205 of this Chapter (§ 205.90 et seq.) shall apply to such an application. A producer that requests such an order shall have the burden of establishing its entitlement to the requested order and shall submit all data, required by these regulations or guidelines issued pursuant thereto or reasonably demanded by ERA.

(5) Conditions and limitations within orders. In addition to the conditions and limitations set forth elsewhere in this section, ERA may, in its discretion, prescribe such other conditions and limitations within an order as are consistent with the requirements of this section and as are determined to be reasonably necessary, either to assure that the purposes of this section are not frustrated, or to promote the effective administration of the programs established by this section.

(6) Revocation or modification of order. A final order shall be subject to revocation or modification, at any time and either retroactively or prospectively or both, as and to the extent that the ERA determines to be appropriate:

(i) if the producer does not obtain the order in good faith or implement the project in good faith; or

(ii) if the order was issued on the basis of a material error or omission of fact of which the producer knew or should have known or to which the producer contributed; or

(iii) if the producer does not adhere to the requirements of this section or any additional conditions and limitations which ERA may prescribe.

(f) Additional procedures and criteria. The ERA may from time to time publish, or otherwise make available to producers and the public, additional instructions or guidelines setting forth procedures to be followed and criteria to be applied in obtaining or making the certifications provided for in paragraphs (d) or (e) of this section; provided, however, that such instructions or guidelines shall not be mandatory or binding upon the ERA or the certifying authority, and shall not create or enlarge any procedural or substantive rights against the ERA.

(g) Base production control level adjustments under the tertiary incremental program; measurement of post-certification production. Notwithstanding any other provision of this part, and except as otherwise prescribed by ERA, a producer shall adjust the base production control level for a property (including any unitized property for which a unit base production control level has been established) on which a qualified tertiary enhanced recovery project is being implemented, and shall measure production from such property, as follows:

(1) Projects involving an entire property. Where the project is determined to involve or affect the entire property, upon commencement of the production of incremental crude oil (as determined in the certification) the property's base production control level shall be deemed to be the same proportion to the total amount of non-incremental crude oil (as such non-incremental crude oil is determined in the certification for the period concerned) as the amount of old crude oil produced from such property in the twelve-month period immediately preceding the month in which incremental crude oil production commences bears to total crude oil produced from that property during the same twelve-month period. The property's base production control level may thereafter be adjusted as provided in § 212.76 or as provided in the preceding sentence, i.e., except as the non-incremental crude oil production from the property (as determined in the certification) may vary from period to period.

(2) Projects involving a portion of a property. Where the project is determined to involve or affect only a portion of a property (including a unitized property for which a unit base production control level has been established), upon commencement of the production of incremental crude oil (as determined in the certification) the unaffected portion of the property shall receive the entire property's base production control level existing at the time incremental crude oil production commences. The amount of crude oil production to be credited against such base production control level shall be the sum of (i) the separately measured actual production from the unaffected portion of the property, plus (ii) the amount of non-incremental production (as established in the certification) for the project area for the period concerned (or the actual production from the project area for that period, if less than said non-incremental production). The base production control level may thereafter be adjusted as provided in § 212.76. It shall be a condition of any certification applying to only a portion of a property that the producer shall undertake to measure actual production from the affected portion and the unaffected portion separately, by such means as certifying authority may from time to time prescribe either at the time of certification or at any time thereafter.

(h) Reporting requirements. (1)(i) Monthly producer reports. By the close of each month, a qualified producer shall file with DOE a report in which the producer shall certify (A) the recoupable allowed expenses attributed to it during the previous month; (B) the project from which each such expense is attributed; (C) the cumulative total of recoupable allowed expenses attributed to it at the close of the previous month; (D) the amount of tertiary incentive revenue received by it during the previous month; (E) the cumulative total of tertiary incentive revenue received by it at the close of the previous month; (F) the properties from which tertiary incentive crude oil was sold by or for the interest of the producer and the amounts sold from each such property during the previous month; (G) the maximum lawful selling price(s) of crude oil from each such property absent the provisions of paragraph (a)(2) of this section; (H) the price at which tertiary incentive crude oil was actually sold at each such property; and (I) the names of the purchasers of tertiary incentive crude oil. Copies of the certifications provided to purchasers of tertiary incentive crude oil under § 212.131 shall be attached to this report.

(ii) Annual CPA opinion. By January 31 of each year after 1980, each qualified producer shall submit to DOE an opinion by a certified public accountant attesting that during the course of its annual audit nothing has come to its attention that causes it to believe that the reports submitted by that producer in accordance with paragraph (h)(1)(i) of this section are inaccurate.

(iii) An operator of a tertiary project may file the reports required by paragraph (h)(1)(i) of this section on behalf of any producer that is a qualified producer with respect to the project: Provided, That, (A) the operator and the producer agree to the operator's filing; (B) the producer is not a qualified producer with respect to any other project; and (C) no crude oil is sold by or for the behalf of the producer pursuant to paragraph (a)(2) of this section except from properties on which the project is located. For purposes of this paragraph, the term "operator of a tertiary project" shall include with respect to a particular project any qualified producer for that project that purchases crude oil produced from a property on which that project is located.

(2)(i) Monthly project reports. With respect to a particular project, the qualified producers therefor shall submit to DOE by the close of each month a consolidated monthly report in which they shall certify (A) the recoupable allowed expenses for the previous month and; (B) the amount of such recoupable allowed expenses attributable to each qualifed producer.

(ii) Annual CPA opinion. By January 31 of each year after 1980, the qualified producers with respect to a particular project shall submit to DOE an opinion by a certified public accountant attesting that during the course of its annual audit nothing has come to its attention that causes it to believe that the reports with respect to that project submitted during the prior calendar year in accordance with paragraph (h)(2)(ii) of this section are inaccurate.

(3) Initial report. A producer shall file with the certifying authority an initial report on each project with respect to which the producer is a qualified producer prior to its recouping any allowed expenses attributable to it from that project. The contents of this report will be set forth in the guidelines to this section.

(4) Annual report. Each year the qualified producers with respect to a project shall file an annual report on the status of that project with DOE by the anniversary of the filing of the first initial report on that project. The contents of this report will be set forth in the guidelines to this section.

[45 FR 40107, June 13, 1980; 45 FR 47624, July 15, 1980]

APPENDIX TO SECTION 212.78

Items on Which Allowed Expenses for Self-Certifiable EOR Techniques May Be Based

1. Conventional Steam Drive and Cyclic Steam Injection.—a. The cost of any additives or gases used in conjunction with the steam flood to increase recovery efficiencies.

b. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids.

c. The costs of surface boilers not fueled by oil or gas (such as coal and solar powered generators) or non-surface boilers (such as down-hole steam generators).

d. The cost of fuel, excluding crude oil or refined petroleum products, natural gas and/or electricity, used by boilers for surface steam generation.

2. Unconventional Steam Drive.—a. The cost of any additives or gases used in conjunction with the steam flood to increase recovery efficiencies.

b. The costs of conventional hydrocarbon fuel fired boilers provided that, with respect to a particular year, the amount of allowed expenses based on such costs may not exceed the amount of depreciation reported to the IRS with respect to such costs for that year.

The costs of surface boilers not fueled by oil or gas (such as coal and solar powered generators) or non-surface boilers (such as down-hole steam generators).

d. The costs of fuel, excluding crude oil or refined petroleum products, natural gas and/or electricity, used by surface boilers for steam generation.

e. Well costs.

f. The costs of valves, regulators, insulation, coatings, etc., in fluid injection distribution systems, necessary to maintain the injection fluid quality of the project.

g. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids from the project.

3. In Situ Combustion.—a. The costs of purchased compressed air plus any oxygen, steam, or water used in association with combustion at the project site.

b. The costs of air compressors and prime movers used for air compression, provided that with respect to a particular year the amount of allowed expenses based on such costs may not exceed the amount of depreciation reported to the IRS with respect to such costs for that year.

c. The costs of fuel for operation of air compressors and prime movers.

d. Well costs.

e. The costs of valves, regulators, insulation, coatings, etc., in fluid injection distribution systems, necessary to maintain the injection fluid quality of the project.

f. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids from the project.

4. Miscible Fluid Flooding.—a. The costs of injected fluids and additive for use at the project site.

b. The costs of compressors and prime movers used for the compression of injection fluids provided that, with respect to a particular year the amount of allowed expenses based on such costs may not exceed the amount of depreciation reported to IRS with respect to such costs for that year.

c. The costs of fuel for operation of compressors and prime movers.

d. Well costs.

e. The costs of valves, regulators, insulation, coatings, etc., in fluid injection distribution systems, necessary to maintain the injection fluid quality of the project.

f. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids from the project.

5. Micro-emulsion and Alkaline Flooding.—a. The costs of the chemicals (including surfactants, polymers, alcohols, and caustics) in jected into the formation plus any fluids used in association with the surfactant flood at the project site.

b. The costs of capital equipment used for mixing of chemicals on the project site, provided that with respect to a particular year the amount of allowed expenses based on such costs may not exceed the amount of depreciation reported to the IRS with respect to such costs for that year.

c. The costs of chemicals to preserve quality of injectants (including oxygen removal, control of iron contamination and biocides for control of bacteria).

d. The costs of water purchased to meet quality specifications to protect chemicals or costs of treating equipment and chemicals required to condition water to meet quality specifications to protect chemicals.

e. The costs of process control equipment, instruments, and filters.

f. Well cost.

g. The costs of valves, regulators, insulation, coatings, etc., in fluid injection distribution systems, necessary to maintain the injection fluid quality of the project.

h. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids from the project.

6. Immiscible Fluid Flooding.—a. The costs of injected fluids (excluding hydrocarbons) and additives for use at the project site.

7. Polymer Augmented Waterflooding.—a. Costs of the polymers injected into the formation.

The General Guidelines on Tertiary Enhance Recovery Project Review appearing after the Appendix to section 212.78 are revised to read

as follows.

GENERAL GUIDELINES ON TERTIARY INCREMENTAL AND INCENTIVE PROGRAMS

I. Introduction

These guidelines are intended to assist crude oil producers and other potentially affected parties in complying with the provisions of 10 CFR 212.78. These guidelines are issued pursuant to, and subject to the limitations of, 10 CFR 212.78(f). They are not to be construed as mandatory upon the ERA, nor do they confer or enlarge any rights, procedural or substantive, against the ERA. They are intended to be informational in nature. Producers and other parties must consult and adhere to all applicable regulations, including (but not necessarily limited to) §§ 212.78 and 205.90 et seq. of Title 10 of the Code of Federal Regulations. Finally, these guidelines are subject to revision from time to time. Although the ERA will attempt to publish any substantial revisions, the published guidelines may not always reflect all changes. Therefore, producers should confirm that they have the most recent guidelines, and otherwise inform themselves as to current ERA procedures, by contacting the Manager, Tertiary Enhanced Recovery Program, Office of Petroleum Operations, Economic Regulatory Administration.

II. Initial Report

A particular project shall not be eligible for the pricing provisions of section 212.78 concerning tertiary incremental crude oil and tertiary incentive crude oil unless an initial report has been submitted to DOE with respect to that project. This initial report must contain the following information:

1. Name and address of producer (firm, including an individual).

2. Parent, subsidiary, unit operator.

3. Parent company if subsidiary.

4. Name, address, and working interest fraction of each working interest in project.

5. Location of project: state, counties, field, reservoir (I.D. number if available), leases embraced in project (if fractional leases, describe boundaries precisely.

Include map(s) showing boundaries, existing producing, injection, service and inactive wells and proposed wells in each category.

6. Production history:

History of primary, secondary, and prior tertiary recovery operations.

Extent of current development.

Status of wells.

7. Tertiary method(s) employed.

8. Reservoir characteristics:

Oil gravity, (°API) ----------------

Oil saturation, (fraction) ---------

Oil in place

Original oil in place (bbls) -------

Present oil in place (bbls) --------

Oil type:

Paraffinic ------------------------

Naphthenic ------------------------

Asphaltic --------------------------

Oil viscosity (cp) -----------------

Rock type:

Sandstone --------------------------

Carbonate --------------------------

Coarse Clastic ---------------------

Other (describe) -------------------

Depth (feet) -----------------------

Thickness (feet) -------------------

Temperature (°F) -------------------

Permeability (md) ------------------

Free gas:

Significant -----------------------

Insignificant ---------------------

Wettability:

Oil wet ----------------------------

Water wet --------------------------

Dip:

Significant --- degree --- direction

Insignificant ---------------------

Stratification:

Significant -----------------------

Insignificant ---------------------

Salinity (% tds) -------------------

Consolidation:

Friable ----------------------------

Indurated --------------------------

Clay Swelling:

Significant -----------------------

Insignificant ---------------------

Other significant reservoir characteristics: (describe) --------------------------

9. Laboratory Analysis:

Certifying firm (producer) ---------

Contract Lab ------ (Name and address)

10. Project Characteristics (if applicable):

a. In-situ combustion projects:

Project area (acres) ---------------

Pattern:

Line -------------------------------

Single -----------------------------

Multiple (describe) ----------------

Pattern area (acres):

Presoak? (yes, no) -----------------

Method:

Wet --------------------------------

Dry --------------------------------

b. Steam drive and cyclic steam projects:

Project area (areas) ---------------

Pattern:

Line -------------------------------

Single -----------------------------

Multiple (describe) ----------------

Presoak? (yes, no) -----------------

Average operation BHP --------------

c. Microemulsion and alkaline flooding projects:

Project area (acres):

Pattern:

Line ------------------------------

Single ----------------------------

Multiple --------------------------

Preflush? (yes, no) ---------------

Agent -----------------------------

Surfactant or alkaline slug:

Size ------------------------------

Concentration ---------------------

Mobility buffer:

Size ------------------------------

Polymer:

Synthetic -------------------------

Biologic --------------------------

d. Miscible fluid and immiscible non-hydrocarbon gas projects:

Miscibility (where applicable):

Partial ---------------------------

Complete --------------------------

Project area (acres):

Pattern:

Line ------------------------------

Single ----------------------------

Multiple --------------------------

Pattern area (acres) --------------

Slug (% PV) -----------------------

Drive fluid:

Water -----------------------------

Other (describe) ------------------

WAG (yes, no) ---------------------

e. Polymer project:

Project area (acres):

Pattern:

Line ------------------------------

Single ----------------------------

Multiple --------------------------

Preflush? (yes, no) ---------------

Agent -----------------------------

Mobility buffer:

Size ------------------------------

Polymer:

Synthetic -------------------------

Biologic --------------------------

10. Planned project time schedule:

Laboratory analysis ---------------

Field pilot (same for Field Development):

Workover existing wells ---------

Install surface tertiary equipment --

Preflush --------------------------

Injection -------------------------

Initial incremental response --------

12. Project Costs:

Contract (or inhouse) laboratory analysis:

Contract engineering ---------------

Authorized surface installations ----

Authorized downhole equipment -------

Authorized drilling ----------------

Injected fluids:

Preflush --------------------------

Injection -------------------------

Direct project supervision ----------

Direct project operation ------------

13. Environmental Information:

a. Has any State or Federal agency prepared an environmental evaluation of this project? If so, please give the name of the agency below and attach a copy of the document. If preparation is in progress, please indicate the name of the governmental official with whom the project can be discussed and give his/her telephone number.

b. Please provide specific information regarding the applicability to your operations of any State or Federal laws, including the Clean Air Act, (42 U.S.C. § 7401 et seq.); the Clean Air Act, (33 U.S.C. § 1251 et seq.); the Safe Drinking Water Act, (42 U.S.C. § 300f et seq.); and the Resource Conservation and Recovery Act, (42 U.S.C. § 6901 et seq.).

For any applicable State or Federal law, please indicate whether a permit or other form of authorization is required, whether it has been obtained, and, if the tertiary recovery operation is in existence now, whether it is in compliance with the requirement. If some form of authorization is required but has not been received, please indicate whether an application has been filed and the date of application, when you expect to receive the authorization, and whether a request has been denied. In all cases, if a permit has been issued, please attach a copy.

c. Please give any additional information which you consider is relevant to an appraisal of the environmental impacts of your operation.

All of the preceding information must be certified by the producer submitting the initial report. In addition, the information requested in sections 6, 7, 8, and 10 must be certified by a professional engineer. The report should be submitted by certified mail to the following address:

Administrator, Economic Regulatory Administration, Department of Energy, Washington, D.C. 20461. Attention: Manager, Tertiary Enhanced Recovery Program, Office of Petroleum Operations.

III. Self-Certification

A. Tertiary Incremental Crude Oil Program:

Under the tertiary incremental crude oil program, market prices may be received for first sales of the incremental crude oil production from a particular property, provided that a producer has certified to ERA the amount of the incremental crude oil from that property and that such amount results from the initiation after September 30, 1979, of a project employing (1) miscible fluid displacement, (2) unconventional steam drive injection, (3) microemulsion flooding, or (4) in situ combustion. This certification should contain a

schedule setting forth the amount of non-incremental and incremental crude oil which will be associated with the project and the basis on which the producer calculated those amounts. In general, for a new project, non-incremental crude oil production is that amount of production from the property or project area which would have occurred had the project not been undertaken.

B. Tertiary Incentive Crude Oil Program:

Under the tertiary incentive crude oil program, a producer may charge market price for first sales of crude oil in order to recover the recoupable allowed expenses attributed to it with respect to a particular project, provided that the producer has certified to ERA that it has contributed to a project employing (1) miscible fluid displacement, (2) conventional steam drive, (3) unconventional steam drive injection, (4) microemulsion flooding, (5) in situ combustion, (6) polymer augmented waterflooding, (7) cyclic steam injection, (8) alkaline flooding, (9) immiscible non-hydrocarbon gas displacement, (10) enhanced heavy oil recovery.

Certifications for both the tertiary incremental and incentive programs should be submitted by certified mail to the following address:

Administrator, Economic Regulatory Administration, Department of Energy, Washington, D.C. 20461. Attention: Manager, Tertiary Enhanced Recovery Program, Office of Petroleum Operations.

IV. ERA Certification

A. Tertiary Incremental Crude Oil Program:

In the event that tertiary incremental crude oil production is not eligible for self-certification by a producer, the producer may request ERA to issue an order that will permit the incremental production from that project to be sold at market prices. Such an order will be granted upon a showing that the period employs a bona fide "tertiary" technique and that incremental production would be economically feasible only if the property is eligible to receive market prices.

B. Tertiary Incentive Crude Oil Program:

A producer which does not employ an EOR technique providing the basis for self-certification may apply to the ERA for participation in the tertiary incentive crude oil program. A producer which may self-certify its eligibility for participation in the tertiary incentive crude oil program may apply to the ERA to permit the recoupment of costs other than those specified as allowed expenses in § 212.78. In either case, ERA may grant such request by issuing orders, provided that the producer has demonstrated that it is employing an EOR technique which involves high levels of risks and costs and that the offset of certain costs is necessary to make the use of that technique an attractive investment opportunity.

C. Procedure for Requesting ERA Certification:

Prior to the issuance of any order described above, a producer must submit an application to ERA in accordance with the general procedures set forth in subpart G of 10 CFR part 205. This application should contain all the information which would be required in the initial report for that project and any other information that would justify the issuance of the requested order(s). With respect to orders concerning the incremental program, the application should specify the incremental production which will be attributable to the project.

Some of the information contained in an application may be regarded as proprietary information. In such a case, the producer should observe the filing requirements of 10 CFR 205.9 (f) as incorporated in 10 CFR 205.91(a). Broadly, this means that applicants should prepare and submit the application in two copies, one of which (the "confidential" copy) contains all information and the other of which (the "non-confidential" copy) deletes the information claimed to be proprietary.

An application should carry a cover page with the applicant's name and authorized signature and be submitted to the following address:

Administrator, Economic Regulatory Administration, Department of Energy, Washington, D.C. 20461. Attention: Manager, Tertiary Enhanced Recovery Program, Office of Petroleum Operations.

V. Annual Report

Annual reports should be submitted to each of the following addresses:

Assistant Secretary Fossil Energy, Department of Energy, Mail Station D107 GTN, Washington, D.C. 20545, Attn: Program Manager, Enhanced Oil Recovery;

and

Bartlesville Energy Technology Center, Department of Energy, P.O. Box 1398, Bartlesville, OK 74003, Attn: Director

(Emergency Petroleum Allocation Act of 1973, 15 U.S.C. § 751 et seq., Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, 15 U.S.C. § 787 et seq., Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, and Pub. L. 95-91; Energy Policy and Conservation Act, 42 U.S.C. § 6201 et seq., Pub. L. 94-163, as amended, Pub. L. 94-385, and Pub. L. 95-70; Department of Energy Organization Act, 42 U.S.C. § 7101 et seq., Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[44 FR 51152, Aug. 30, 1979; 45 FR 40107, June 13, 1980; 45 FR 47624, July 15, 1980]

§ 212.79 Newly discovered crude oil ceiling price rule.

(a) Rule. Notwithstanding the provisions of § 212.73(a), first sales of newly discovered crude oil on or after June 1, 1979, are not subject to the ceiling price limitations of this subpart.

(b) Definitions. For purposes of the section-

"New lease" means any lease entered into on or after January 1, 1979, of an area from which no crude oil was produced and sold in commercial quantities in calendar year 1978.

"Newly discovered crude oil" means: (1) Prior to January 1981, domestic crude oil which is (i) produced from a new lease on the Outer Continental Shelf, or (ii) produced (other than from the Outer Continental Shelf) from a property from which no crude oil was produced in calendar year 1978; or (2) after December 1980, domestic crude oil which is produced from a newly discovered crude oil property.

"Newly discovered crude oil property" means: (1) A new lease on the Outer Continental Shelf; or (2) a property (not on the Outer Continental Shelf) from which no crude oil was produced and sold in commercial quantities in calendar year 1978; or (3) any unitized property that includes only properties that prior to inclusion within the unit qualified as newly discovered crude oil properties. For purposes of this definition, crude oil is produced and sold in commercial quantities from a property if crude oil is produced from that property on a continuing basis. Crude oil shall be deemed to be produced on a continuing basis from a property if installation of a production facility for the crude oil produced from that property has begun.

"Outer Continental Shelf" means Outer Continental Shelf as defined under section 2(a) of the Outer Continental Shelf Lands Act (43 U.S.C. 1331(a)).

(c) Identification of newly discovered crude oil properties.--(1) Filing requirements. By February 1, 1981, or 60 days after newly discovered crude oil is first produced and sold from a property, whichever is later, a producer must prepare and file with the appropriate DOE office a report identifying each property from which it has produced and sold newly discovered crude oil and the basis on which that property qualifies as a newly discovered crude oil property or on which imputed newly discovered crude oil is computed. These reports must include the following information:

(i) The type of legal instrument which establishes the property and its effective date;

(ii) The date on which crude oil first was produced and sold from the property;

(iii) The date on which crude oil first was produced and sold in commercial quantities from the property;

(iv) Where the property is a reservoir that is to be or has been designated as a newly discovered crude oil property, evidence of the reservoir designation by the appropriate governmental authority and the basis upon which the reservoir qualifies:

(v) Where the property is an unitized property, the amount of production that will be certified as imputed newly discovered crude oil and the name of the unitized property; and

(vi) The location of the producer's main place of business.

(2) Failure to file. Notwithstanding the provisions of this § 212.79 and of § 212.131, a producer may not obtain prices exempt from the ceiling price limitations of Subpart D of this part for crude oil produced and sold from a newly discovered crude oil property or from any unitized property from which newly discovered crude oil is imputed in any month after January 1981 during which the report required by this paragraph (c) has not been filed with the DOE.

(Emergency Petroleum Allocation Act of 1973, 15 U.S.C. 751 et seq., Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, 15 U.S.C. 787 et seq., Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, and Pub. L. 95-91; Energy Policy and Conservation act, 42 U.S.C. 6201 et seq., Pub. L. 94-163, as amended, Pub. L. 94-385, and Pub. L. 95-70; Department of Energy Organization Act, 42 U.S.C. 7101 et seq., Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[44 FR 25832, May 2, 1979; 45 FR 78594, Nov. 25, 1980]

APPENDIX A TO SUBPART D OF PART 212-Monthly Price adjustments from February 1976 through August 31, 1980

Schedule No. 19 of Monthly Price Adjustments

[Effective June 1, 1980]

Month	Lower tier, May 15, 1973, posted price [1] (plus)	Upper tier, Sept. 30, 1975, posted price [2] (plus)
1976:		
February -----	1.35	—1.32
March --------	1.38	--1.25
April --------	1.41	--1.18
May ----------	1.45	--1.11
June ---------	1.48	—1.05
July ---------	1.48	--1.05
August -------	1.48	—1.05
September ----	1.48	--1.05
October ------	1.48	--1.05
November -----	1.48	--1.05
December -----	1.48	—1.05
1977:		
January ------	1.48	—1.25
February -----	1.48	--1.25
March --------	1.48	--1.70
April --------	1.48	--1.70
May ----------	1.48	—1.70
June ---------	1.48	--1.70
July ---------	1.48	—1.70
August -------	1.48	--1.70
September ----	1.51	--1.44
October ------	1.54	--1.18
November -----	1.57	-- .92
December -----	1.59	-- .87
1978:		
January ------	1.61	— .82
February -----	1.63	-- .77
March --------	1.66	— .71
April --------	1.69	-- .65
May ----------	1.72	-- .59
June ---------	1.75	-- .52
July ---------	1.78	— .45
August -------	1.81	-- .38
September ----	1.86	— .28
October ------	1.91	-- .17
November -----	1.96	— .06
December -----	1.99	.01
1979:		
January ------	2.02	.08
February -----	2.05	.15
March --------	2.09	.23
April --------	2.13	.31
May ----------	2.17	.39
June ---------	2.21	.48
July ---------	2.25	.57
August -------	2.29	.66
September ----	2.33	.76
October ------	2.37	.86
November -----	2.41	.96
December -----	2.45	1.05
1980:		
January ------	2.49	1.14
February -----	2.53	1.23
March --------	2.57	1.33
April --------	2.61	1.43
May ----------	2.66	1.53
June ---------	2.71	1.64
July ---------	2.76	1.75
August -------	2.81	1.86
September ----	2.87	1.98
October ------	2.93	2.10
November -----	2.99	2.23
December -----	3.04	2.35
1981:		
January ------	3.09	2.47
February -----	3.14	2.59

[1] The price referred to in 10 CFR 212.73(b)(1) or in 212.73(c)(1), 212.73(c)(3), and 212.73(c)(4).
[2] The price referred to in 10 CFR 212.74(b)(1).

This schedule of monthly price adjustments was issued by the Economic Regulatory Administration on November 25, 1980, pursuant to 10 CFR 212.77. It restates without change the lower and upper-tier price ceilings applicable to crude oil produced and sold in the months of February 1976 through November 1980, as determined under 10 CFR 212.73, 212.74, and 212.77. Both lower-tier and upper-tier ceiling prices, which were increased under Schedule No. 20 effective September 1, 1980, are further increased as indicated in this schedule, effective December 1, 1980.

This schedule is effective only through February 28, 1981.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[44 FR 33053, June 8, 1978, Redesignated and amended at 44 FR 37939, June 29, 1979; 44 FR 70122, Dec. 6, 1979; 45 FR 14844, March 7, 1980; 45 FR 38039, June 6, 1980; 45 FR 80483, Dec. 5, 1980]

Subpart E—Refiners

(This subpart is omitted)

Subpart F—Resellers and Retailers.

§ 212.91 Applicability.

This subpart applies to each sale of a covered product, other than crude oil by resellers, resellers-retailers and retailers. For purposes of this subpart, "reseller" includes any entity of a refiner (other than an entity that operates in Puerto Rico) that is engaged in the business of purchasing and reselling covered products, provided that the entity does not purchase more than 5 percent of such covered products from the refiner including any entities that it directly or indirectly controls and provided further that the entity has consistently and historically excercised the exclusive price authority with respect to sales by the entity.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, and Pub. L. 95-70; Department of Energy Organization Act, Pub. L. 95-91, E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)
[42 FR 64864, Dec. 29, 1977]

§ 212.92 Definitions.

For purposes of this Subpart--

"Acquisition cost" means:

(a)(1) For retailers which make three consecutive purchases from the same supplier, the actual purchase price paid for the most recent purchase of a product; or,

(2) For all other retailers, the weighted average purchase price paid for the three most recent purchases computed on a cents per gallon basis.

(3) Notwithstanding the provisions in paragraphs (a)(1) and (2) of this section for any retailer which historically makes more than three purchases in a twenty-four (24) hour period, the acquisition cost is the weighted average purchase price paid in the immediately preceding three day period.

(b) For resellers and reseller-retailers, the cost of product in inventory computed pursuant to the seller's historical accounting practices consistently applied. Resellers and reseller-retailers, which on a firm-wide basis sold five million gallons or less of a product during calendar year 1979, may use the actual purchase price paid for the most recent purchase of that product to calculate acquistion cost. A seller shall consistently use either the actual purchase price or the cost of product in inventory to compute acquisition cost.

(c) The purchase price shall:

(1) Be computed on a cents per gallon basis:

(2) Be substantiated by written evidence of purchase; and

(3) Include transportation cost of bringing the product into inventory.

(d) DOE may disallow any purchases which have the effect of frustrating the purpose of the price regulations.

"Exchange" means, for purposes of this subpart, a transaction in which two firms reciprocally give up and receive refined product or residual fuel oil. The term includes exchanges in which one firm may make a payment in cash or other property to compensate the other for differences in the values of the volumes involved or to compensate the other for costs incurred pursuant to the transaction, and it also includes matching purchase and sale transactions. The term does not include a firm's acquisition, or transfer of refined product or residual fuel oil under a service agreement.

"Increased product costs" means the difference between the weighted average unit cost of a product in inventory and the weighted average unit cost of that product in inventory on May 15, 1973. If the product in inventory is a blend of one or more covered products and one or more non-petroleum-based products, "increased product costs" means either (a) the difference between the weighted average unit cost of the blended product in inventory and the weighted average unit cost of the blended product in inventory on May 15, 1973, or (b) for a blended product which was not in inventory on May 15, 1973, the difference between the weighted average unit cost of the blended product in inventory and the weighted average unit cost of the predominant covered product in inventory on May 15, 1973. [Decreases in the weighted average unit cost of a product in inventory in successive accounting periods are reflected in reductions in the amount of increased costs incurred in those accounting periods, in accordance with § 212.93(c).] If a particular product was not in inventory on May 15, 1973, the date for computing the cost is the most recent day preceding May 15, 1973, when the seller had the product in inventory.

"Increased rental cost" means the rent, in terms of cents per gallon, with respect to that portion of real property leased for purposes of retail gasoline sales, paid to an independent lessor for the calendar month preceding the calendar month in which gasoline is sold minus the rent, stated in terms of cents per gallon, with respect to the same real property leased for purposes of retail gasoline sales, paid to an independent lessor for the month of May 1973. For purposes of this paragraph, "independent lessor" means a lessor which is not directly or indirectly controlled by the lessee concerned or by any firm which directly or indirectly controls that lessee.

"Matching purchase and sale" means, for purposes of this subpart, a transaction in which

two firms sell refined product or residual fuel oil to each other, pursuant to an agreement that the sale by one firm is incident to the sale by the other, and in which the volumes transferred and the cash paid and received by each firm are dependent on the value of the volumes received. The term does not include a firm's acquisition or transfer of refined product or residual fuel oil under a service agreement.

"Product in inventory" means, at the option of the seller concerned, either: (1) The entire, undivided stock of a product, no matter where located, purchased and held for resale by the seller concerned; or (2) that portion of the total stock of a product purchased and held for resale by the seller concerned which constitutes a separate inventory under generally accepted accounting principles consistently and historically applied by the seller concerned. However, the cost of transportation may be included as a cost of product in inventory only up to the point at which the product concerned first comes to rest in facilities which constitute a part of the seller's storage and distribution system.

"Purchase" means to acquire by the payment of money or by exchange.

"Seller" means, except as provided in § 212.91, a parent and the consolidated and unconsolidated entities (if any) which it directly or indirectly controls.

"Service agreement" means an agreement under which a seller, incident to providing a service to another firm, obtains title to refined product or residual fuel oil received from the other firm, subsequently transfers title to the volumes received (or other volumes of similar quantity and quality as that received) back to that firm, and charges a fee for the service.

"Tax cost" means the cost of federal, local, and state excise, sales, and other similiar taxes attributable to gasoline sales and computed on a cents per gallon basis. Federal, state, and local income, property, franchise, and other similar taxes are not included in this amount.

"Vapor recovery system cost" means the unrecovered installation and purchase cost incurred by the seller since May 15, 1973, with respect to a gasoline vapor recovery system required by a Federal, state, or local governmental authority. For purposes of this paragraph, the cost incurred with respect to a vapor recovery system may be recovered in one month or may be prorated over a period of months. Each seller will be required to establish an accounting method by which vapor recovery costs shall be recovered. Once the method is established, the seller will apply the method consistently over the period for the recovery of costs. A seller may not recover in sales of gasoline a total amount attributable to such costs which exceeds the seller's actual vapor recovery system cost. In any one month, the portion of vapor recovery system costs that are available for recovery in that month shall be applied equally to, and shall be deemed to have been recovered on, each gallon of gasoline sold and for purposes of § 212.83(f) shall be deemed to have been recovered before all other non-product costs.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, E.O. 11790, 39 FR 23185, Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[41 FR 18305, May 3, 1976, as amended at 41 FR 19113, May 10, 1976; 42 FR 39197, Aug. 3, 1977; 43 FR 24268, June 5, 1978; 43 FR 59822, Dec. 21, 1978; 43 FR 60869, Dec. 29, 1978; 44 FR 45355, Aug. 1, 1979; 45 FR 29551, May 2, 1980; 45 FR 40106, June 13, 1980]

§ 212.93 Price rule.

(a)(1) Except for sales of gasoline, unless as provided in paragraph (a)(5) of this section, a seller may not charge a price for an item subject to this subpart which exceeds the weighted average price at which the item was lawfully priced by the seller in transactions with the class of purchaser concerned on May 15, 1973, plus an amount which reflects, on a dollar-for-dollar basis, the increased product costs concerned. Each seller shall maintain records sufficient to justify prices charged which reflect increased product costs, including, if applicable, records which demonstrate that the seller qualifies to determine increased product costs according to separate inventories. With respect to an item which is blended by the seller, and which was not sold by the seller on or before May 15, 1973, the "weighted average price at which the item was lawfully priced by the seller in transactions with the class of purchaser concerned on May 15, 1973," shall be imputed to be lawful price charged by the seller for the predominant covered product in the blend in transactions with the class of purchaser concerned on May 15, 1973.

(2)(i) With respect to retail sales of gasoline by retailers, a retailer may not charge a price in a sale of any type or grade of gasoline which exceeds the most recent acquisition cost, plus 17.7 cents per gallon, plus tax costs attributable to sales of that type or grade of gasoline. Beginning December 15, 1979, DOE shall adjust semi-annually the fixed cents per gallon amount to reflect the GNP deflator.

(ii) Except as provided in subparagraph (5)

of this paragraph, a reseller-retailer may not charge a price in a retail sale of any type or grade of gasoline which exceeds its most recent dealer tank wagon price charged to the nearest independent retailer in the most recently preceding 30-day period, plus 17.7 cents per gallon, plus tax costs attributable to sales of that type or grade of gasoline. If the reseller-retailer has no dealer tank wagon sales to an independent retailer in the most recently preceding 30-day period, the price may not exceed the reseller-retailer's acquisition cost, plus 26.3 cents per gallon, plus tax costs attributable to sales of that type or grade of gasoline. Beginning June 15, 1980, the DOE shall adjust semi-annually the fixed cents per gallon amount to reflect the GNP deflator.

(3)(i) Upon the recommendation of the Governor of a State, the ERA Administrator may increase the fixed cents per gallon markup as described in paragraph (a)(2) of this section for all or some of the retailers or reseller-retailers in the State. The amount of markup increase granted to a retailer, reseller-retailer, or class of reseller-retailers or retailers shall not exceed the amount of cost increase experienced by the retailer, reseller-retailer, or class of reseller-retailers or retailers.

(ii) For purposes of this section, the term "Governor of a State" includes the Governors of the 50 States, and the Chief Executive Officers of the District of Columbia, Puerto Rico, and the territories and possessions of the United States, other than the Panama Canal Zone, and further includes their delegates.

(iii) Any increase in the fixed cents per gallon markup described in paragraph (a)(2) of this section that was granted by the Governor of a State prior to May 19, 1980, in accordance with paragraph (a)(3) of this section as then in effect, shall continue to be valid in accordance with the terms of that increase subject to disallowance by the ERA Administrator at any time.

(4) Except as provided in paragraph (5) of this paragraph, with respect to reseller sales of gasoline by resellers and reseller-retailers, a seller may not charge a price in a sale for any type or grade of gasoline which exceeds the most recent acquisition cost, plus 8.6 cents per gallon, plus tax costs attributable to sales of that type or grade of gasoline. Beginning June 15, 1980, the DOE shall adjust semi-annually the fixed cents per gallon amount to reflect the GNP deflator.

(5) Notwithstanding any other provision of this paragraph, a reseller or reseller-retailer may elect to compute the maximum lawful selling price for all gasoline sales pursuant to paragraph (a)(1) of this section provided the reseller or reseller-retailer:

(i) Before July 1, 1980, notifies the Assistant Administrator of Enforcement in writing of its election; and

(ii) Consistently applies the provisions in this section in effect on April 30, 1980, and does not apply the provisions in paragraphs (a)(2) and (4) of this section. Any firm which does not elect to compute maximum lawful selling prices pursuant to this subpargraph will be deemed to have applied the provisions in paragraph (a)(2) and (4) of this section beginning May 1, 1980.

(b) With respect to sales of covered products other than gasoline, unless gasoline is priced pursuant to paragraph (a)(5) of this section, then notwithstanding paragraph (a)(1) of this section:

(1) With respect to gasoline: (i) In retail sales, a seller (other than a retailer) may charge one cent per gallon in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section, and, with respect to all other sales a seller may charge one-half cent per gallon in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section to reflect non-product cost increases that the seller incurred after May 15, 1973, provided that, subsequent to January 1, 1979, such non-product cost increases shall not include those costs that are or could have been recovered under either paragraph (b)(1)(ii)(B) or paragraph (b)(1)(ii)(C) of this section.

(ii)(A) Beginning with March 1974, in retail sales of gasoline, a seller (other than a retailer) may charge two cents per gallon of gasoline in excess of the amount otherwise permitted to be charged for that item pursuant to this section, including paragraph (b)(1)(i) of this section, to reflect increases in non-product costs incurred by the seller concerned since May 15, 1973, provided that, subsequent to January 1, 1979, such non-product cost increases shall not include those non-product costs that are or could have been recovered under either paragraph (b)(1)(ii)(B) or paragraph (b)(1)(ii) (C) of this section.

(B) Beginning January 1, 1979, in retail sales of gasoline, a seller (other than a retailer) may charge an amount in excess of the price otherwise permitted to be charged for that item pursuant to this section (including paragraphs (b)(1)(i) and (b)(1)(ii)(A) of this section), which reflects increased rental costs not otherwise recovered.

(C) Beginning January 1, 1979, in retail sales of gasoline, a seller (other than a retailer) may charge an amount in excess of the price otherwise permitted to be charged for that item pursuant to this section (including paragraphs (b)(1)(i) and (b)(1)(ii)(A) and (B)), which reflects a portion of vapor recovery system cost as set forth in § 212.92 not otherwise recovered.

(iii) Beginning with April 1974, with re-

spect to all sales of gasoline other than retail sales, a seller that had a total sales volume of covered products in calendar year 1973 of less than 100 million gallons may charge one-half cent per gallon of gasoline in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section including paragraph (b)(1)(i) of this section to reflect non-product cost increases which the seller incurred after May 15, 1973, and a seller that had a total sales volume of covered products in calendar year 1973 of 100 million gallons or more may charge one-quarter cent per gallon of gasoline in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section, including paragraph (b)(1)(i) of this section to reflect non-product cost increases which the seller incurred after May 15, 1973.

(iv) Beginning January 1, 1980, with respect to all sales of gasoline other than retail sales, which are delivered by the seller, a seller that had a total sales volume of covered products in calendar year 1973 of less than 100 million gallons may charge an additional one cent per gallon for gasoline (which is delivered by the seller) in excess of the amount otherwise permitted to be charged for that gasoline pursuant to the provisions of this section including paragraph (b)(1)(i) and (iii), to reflect non-product cost increases and a seller that had a total sales volume of covered products in calendar year 1973 of 100 million gallons or more may charge an additional one-half cent per gallon for gasoline (which is delivered by the seller) in excess of the amount otherwise permitted to be charged for that gasoline pursuant to the provisions of this section including paragraph (b)(1)(i) and (iii), to reflect nonproduct cost increases.

(v) With respect to retail sales of gasoline by reseller-retailers which sell gasoline to independent retailers at dealer tank wagon prices, a reseller-retailer may not charge a price in retail sales of gasoline at a retail outlet which exceeds the most recent dealer tank wagon price the reseller-retailer charged to the nearest independent retailer to that retail outlet, plus 17.7 cents per gallon, plus tax costs. Beginning December 15, 1979, DOE shall adjust semi-annually the fixed cents per gallon amount to reflect the GNP deflator.

(2) With respect to middle distillates:

(i) In all retail sales, (A) beginning with April, 1974, a seller may charge one cent per gallon in excess of the amount otherwise permitted to be charged for the item concerned pursuant to the provisions of this section, including paragraph (b)(1)(i) of this section, to reflect non-product increases which the seller incurred after May 15, 1973; and

(B) In sales of aviation fuels by fixed base operators, beginning with December, 1975, a seller may charge three cents per gallon in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section, including paragraph (b)(2)(i)(A) of this section, to reflect nonproduct cost increases which the seller incurred after May 15, 1973;

(ii) In all sales other than retail sales, (A) a seller that had a total sales volume of covered products in calendar year 1973 of less than 100 million gallons may charge one-half cent per gallon in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section, including paragraph (b)(1)(i) of this section, to reflect nonproduct cost increases which the seller incurred after May 15, 1973; and

(B) A seller that had a total sales volume of covered products in calendar year 1973 of 100 million gallons or more may charge one-quarter cent per gallon in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section, including paragraph (b)(1)(i) of this section, to reflect non-product cost increases which the seller incurred after May 15, 1973.

(3) With respect to residual fuel oil beginning with April 1974: in retail sales, a seller may charge three-fourths cent per gallon in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section, to reflect non-product cost increases which the seller incurred after May 15, 1973; and, with respect to all other sales, a seller may charge one-fourth cent per gallon in excess of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section, to reflect nonproduct cost increases which the seller incurred after May 15, 1973.

(4) With respect to sales of propane, butane, and natural gasoline beginning with March 1977: (i) A seller, which sold fewer than five million gallons of propane, butane, and natural gasoline in the immediately preceding fiscal year, may charge a price in excess of the amount otherwise permitted to be charged for propane, butane or natural gasoline pursuant to the provisions of this section to reflect increased non-product cost which the seller incurred since 1973: Provided, That the amount of increased non-product costs may be calculated only pursuant to either paragraph (A) of § 219.93(b)(4)(iii), which permits computation and pass-through of increased non-product costs only for propane (and not for butane and natural gasoline), or paragraph (B) of § 212.93(b)(4)(iii), which permits computation and passthrough of increased non-product costs for propane, butane, and natural gasoline. However, any seller which elects to pass through increased non-product cost pursuant to paragraph (B) of § 212.93(b)(4)(iii), in subsequent months may not pass through increased non-product cost pursuant to paragraph (A) of

§ 212.93(b)(4)(iii).

(ii) A seller with total sales of propane, butane, and natural gasoline on five million gallons or more during the immediately preceding fiscal year may charge a price in excess of the amount otherwise permitted to be charged for propane, butane, or natural gasoline to reflect increased non-product cost which the seller has incurred since 1973 provided that the seller calculates non-product cost increases pursuant to § 212.93(b)(4)(iii)(B).

(iii) Maximum allowable amounts of increased non-product costs. The maximum amounts of increased non-product costs which may be reflected in prices charged for propane, or for propane, butane, and natural gasoline pursuant to § 212.93(b)(4)(i) and (ii) are either:

(A) Seven cents per gallon with respect to all retail sales of propane except those to the petrochemicals industry, to public utilities and to synthetic natural gas plants; one cent per gallon with respect to retail sales of propane to the petrochemicals industry, to public utilities and to synthetic natural gas plants; and one-half cent per gallon with respect to all other sales of propane.

(B) The amount of increased non-product cost incurred by the firm since May 1973, which is computed pursuant to the factor "E^t" as follows:

E^t = the total increased non-product costs attributable to sales of propane, butane, and natural gasoline: Provided, that such costs are included only to the extent that such costs are attributable to propane, butane, and natural gasoline sales operations under the customary accounting procedures generally accepted and historically and consistently applied by the firm concerned, and are not included in comcomputing May 15, 1973, prices or in computing increased product costs. The costs treated as paid or incurred during a firm's fiscal year by inclusion is "E^t" shall not exceed the amounts of such costs actually paid or incurred during that fiscal year "E^t" shall be computed by adding the amounts calculated by applying the following formula, "E_n^t," separately to § 212.93(v)(4)(iii)(B), paragraphs (I) through (VII).

$$E_n^t = V^t(C_n^z V^z) -- (C_n^x / IV^x)$$

E_n^t is the total increased non-product costs of the type "n": Provided, that such costs are included only to the extent that they are attributable to propane, butane, and natural gasoline sales operations under generally accepted accounting practices historically and consistently applied by the firm concerned and are not included in computing May 15, 1973, prices or in computing increased product costs.

Where:

"n" = references a category of non-product cost attributable to propane, butane, and natural gasoline sales operations as in paragraphs (I) through (VII), and is respectively labor, utility, interest, tax, maintenance, depreciation and overhead cost increases.

"V^t" = the total volume of propane, butane, and natural gasoline sold by the firm in the period "t."

V^z = the total volume of propane, butane, and natural gasoline sold by the firm in the period "z."

V^x = the total volume of propane, butane, and natural gasoline sold by the firm in the period "x."

C_n^z = the total dollar amount of the particular non-product cost of the type "n" incurred in the period "z."

C_n^x = the total dollar amount of the particular non-product cost of the type "n" incurred in the period "x."

"t" = the month of measurement (the month of measurement is the month immediately preceding the current month).

"x" = the nine month period beginning January 1, 1973, and ending September 30, 1973, plus the result of adding the three month period beginning October 1, 1972, and ending December 31, 1972, and the three month period beginning October 1, 1973, and ending December 31, 1973, and dividing that sum by two.

"z" = the twelve month period ending on the last day of the month of measurement, "t."

(1) Labor cost increase. Labor cost increase is computed by applying the formula for "E_n^t" above. For purposes of this computation "C" refers to the total dollar amount of direct and indirect remuneration or inducement for personal services which are reasonably subject to valuation for those personnel employed by the firm and directly involved in propane, butane, and natural gasoline sales operations, except personal services provided by personnel which own any portion of or receive any profits from the firm involved. (This exception does not include personnel which own stock in the firm if it is a public corporation or participants in any type of profit sharing plan historically offered by the firm.) No amount included in maintenance cost increase may be included in labor cost increase. The calculation must be based on the historical accounting practices employed by the firm and must be substantiated by a supporting document which summarizes the personnel considered in the calculation and the date of any remuneration increases.

(2) Utility cost increase. Utility cost increase is computed by applying the formula for "E_n^t" above. For purposes of this computation "C" refers to the dollar amount of costs in-

curred for utilities.

(3) Interest cost increase. Interest cost increase is computed by applying the formula for "E_n^t" above. For purposes of this computation "C" refers to the dollar amount of costs incurred for interest.

(4) Federal, state, and local tax cost increase. Federal, state, and local tax cost increases is computed by applying the formula for "E_n^t" above. For purposes of this computation "C" refers to the dollar amount of federal, state, and local property, excise, franchise and other similar taxes incurred which are associated with propane, butane, and natural gasoline sales operations. Federal, state, and local income tax are not includable in this amount.

(5) Maintenance cost increase. Maintenance cost increase is computed by applying the formula for "E_n^t" above. For purposes of this computation "C" is the dollar amount of operating cost attributable to maintenance operations which are assoicated with propane, butane, and natural gasoline sales operations. Maintenance cost increase includes the cost of contract maintenance.

(6) Depreciation cost increase. Depreciation cost increase is computed by applying the formula for "E_n^t" above. For purposes of the computation "C" is the cost attributable to the depreciation of equipment, machinery, and the facility which are associated with propane, butane, and natural gasoline sales operations: Provided, That such costs are computed according to generally accepted accounting practices historically and consistently applied by the firm and to the extent that such costs are not otherwise covered by this section. If Form 10-K is filed with the Securities and Exchange Commission or an analogous report is filed with a state regulatory agency, the amount computed for depreciation cost increase must be consistent with the figures used in preparing Form 10-K or such analogous report. Accounting procedures used to compute depreciation cost increase by resellers and retailers which do not file such form or report, or on whose behalf such form or report is not filed, must be calculated according to generally accepted accounting practices historically and consistently applied by the firm concerned for certified annual financial reports prepared by an independent accounting firm. No capital investments may be included in non-product costs as expenses; all such investments must be capitalized and depreciated and included in the computation of "E_n^t" for depreciation cost increase.

(7) Overhead cost increase. Overhead cost increase is computed by applying the formula for "E_n^t" above. For purposes of this computation "C" is the dollar amount of costs of rent of real property, postage, office supplies, normal gas losses, insurance, employees' uniforms, outside legal and accounting fees, rent of personal property, bad debts, travel and meetings, dues and publications, commission agent fees (based on volumetric payment) and transportation costs directly attributable to propane, butane, and natural gasoline sales operations and not included in the calculation of increased product cost, provided that such costs are computed according to generally accepted accounting practices and historically and consistently applied.

(8) Equity-Owner Salaries Cost Increase. Cost increases relating to the equity-owner salaries are computed by applying the formula for E_n^t above. For purposes of this computation, "C" refers to the costs attributable to those salaries which are paid to personnel who own all, or any portion of, or receive profits from, the firm involved, who participate directly in the management or sales operations of the firm. A portion of an owner's current salary can be shown as an increased cost, up to the weighted average percentage increase in salaries granted to all other employees of the firm since May 15, 1973, or the initial quarter of the firm's operations, and to the extent that such salaries are reasonable and bear a direct relationship to services devoted to the firm's activities. Owner salary increases are prohibited as an allowable cost for any owner who did not draw a salary during May 1973, or the initial quarter of operations of the firm except where an owner has drawn a salary prior to May 1, 1979, but did not draw a salary during May 1973 or the initial quarter of the firm's operations because of economic or other financial considerations. In such a case, a portion of the owner's current salary can be shown as an increased cost, up to the weighted average percentage increase in salaries granted to all other employees of the firm since May 15, 1973, or the initial quarter of the firm's operations. The reallocation of "net profits" from operations to "owner salaries" for the sole purpose of increasing the costs available for pass through is not permitted.

(5) With respect to an allocation sale of petrochemical feedstocks (except benzene and toluene) made pursuant to § 211.186, the maximum price that may be charged is 115 percent of the amount otherwise permitted to be charged for that item pursuant to the provisions of this section.

(c) A seller which charges a price in excess of the weighted average price at which the product concerned was lawfully sold by that seller in transactions with the class of purchaser concerned on May 15, 1973, may continue to charge that price only as long as the product cost increases (and, as appropriate, the net increases in non-product costs) which have been incurred since May 15, 1973, and which support that price, continue to be incurred. Price

reductions shall be made under this paragraph as soon as any computation of increased product costs under § 212.92 [or, as appropriate, any computation of increased non-product costs under § 212.93(b)] reveals a net cost decrease, and the frequency of these computations shall be maintained in accordance with the customary accounting practices of the seller concerned. However, to the extent that unrecovered increased product costs have been carried forward under paragraph (e) of this section and are available to justify continuation of a price no longer supported by increased product costs (or, as appropriate, by net increases in non-product costs), those unrecovered increased product costs may be used to justify continuation of that price.

(d) In computing the May 15, 1973, selling price, a firm may not exclude any temporary special sale, deal or allowance in effect on May 15, 1973. If no transaction occurred on May 15, 1973, the most recent day preceding May 15, 1973, when a transaction occurred shall be used for purposes of applying the price rule. If the seller first offered an item for sale after May 15, 1973, and prior to the effective date of this paragraph, the first day when the item was offered for sale shall be used for purposes of applying the price rule.

(e) Notwithstanding the provisions of paragraph (a)(1) of this section:

(1)(i) For gasoline priced pursuant to paragraph (a)(5) of this section and other covered products, if a seller charges prices for a particular product that result in the recoupment of less total revenues than the total amount of increased product costs of that product incurred during the month, the amount of increased product costs not recouped by a price adjustment in the subsequent month pursuant to paragraph (a) of this section may also be added to the May 15, 1973, selling prices of that product in a subsequent month at the time the selling prices are computed pursuant to paragraph (a). A seller shall calculate its amount of increased product cost of a particular product not recouped, since the most recent price increase after November 1, 1973, to include the following: (A) Any "increased product costs" not added to the May 15, 1973, selling price at the time of the most recent price increase implemented after November 1, 1973, multiplied by the volume sold since that price increase, plus (B) increases in the weighted average unit cost above the weighted average unit cost which was used to calculate the most recent price increase implemented after November 1, 1973, multiplied by the volume of product purchased at each such increased product cost, less, (C) any decrease in the weighted average unit cost from the weighted average unit cost which was used to calculate the most recent price increase implemented after November 1, 1973, multiplied by the volume of product purchased at each such lesser cost.

(ii) With respect to covered products other than gasoline, when a seller calculates its amount of increased product costs not recouped under this paragraph, it shall calculate its revenues as though the greatest amount of increased product costs actually added to the May 15, 1973, selling price of that covered product and included in the price charged to any class of purchaser had been added in the same amount to the May 15, 1973, selling price of such covered product and included in the price charged to each class of purchaser; except that where an equal amount of increased product cost is not included in the price charged to a purchaser because of either a price term of a written contract covering the sale of such product which was entered into on or before September 1, 1974, such portion of the increased product costs not included in the price charged to such a purchaser need not be included in the calculation of revenues.

(2) With respect to sellers of propane, butane, and natural gasoline beginning May 1, 1977, the amount of increased non-product cost calculated pursuant to paragraph (b)(4) of this section for propane, butane, or natural gasoline and not recouped by a price adjustment in the subsequent month pursuant to paragraph (b)(4) of this section may also be added to the May 15, 1973, selling price of propane, butane, or natural gasoline at the time the selling prices are computed pursuant to paragraphs (a) and (b)(4) of this section.

(3) With respect to retail sales of gasoline by retailers, increased costs not recouped on or before July 16, 1979, shall not be carried forward pursuant to paragraph (e)(1) of this section to be recouped after July 16, 1979. Except when gasoline is priced pursuant to paragraph (a)(5) of this section, with respect to all other sales of gasoline, increased costs not recouped on or before May 1, 1980, shall not be carried forward pursuant to paragraph (e)(1) of this section to be recouped after May 1, 1980.

(4) When a reseller-retailer calculates the amount of increased costs not recouped that may be added to the May 15, 1973, selling price of gasoline to compute maximum allowable prices, it may, notwithstanding the general rule in paragraph (e)(1) of this section, with respect to retail sales of gasoline, include the amount by which the greatest amount of increased costs actually added to any May 15, 1973, selling price of gasoline to any class of purchaser exceeds the amount of increased costs which could have been added to the May 15, 1973, selling price in retail sales of gasoline but for the limitation in § 212.93(b)(4).

(f) Special rules for natural gas liquid products--(1) Exception to equal application rules for propane. Notwithstanding the provisions of paragraph (e) of this section, a

seller may comply with the provisions of this section by applying unequal amounts of increased product costs to the weighted average May 15, 1973, selling price of propane to classes of purchaser of propane, provided that the highest amount of increased product cost applied to the weighted average May 15, 1973, selling price to any class of purchaser shall not exceed by more than one hundred (100) percent the amount of increased product cost applied to the weighted average May 15, 1973, selling price to any other class of purchaser, and, provided further, that no greater amount of increased product cost shall be applied to the weighted average May 15, 1973, selling price of propane in sales to any class of purchaser which includes either an independent marketer, as defined in § 211.51 of part 211 of this chapter, or a purchaser that uses the product for residential use, as defined in § 211.51, than is applied to the weighted average May 15, 1973, selling price of propane in sales to any other class of purchaser.

(2) Separate cost of product in inventory for certain imported propane, butane, natural gasoline or natural gas liquids. Any seller of imported propane, butane, natural gasoline or natural gas liquids (or domestically produced propane, butane, natural gasoline or natural gas liquids exchanged for imported propane, butane, natural gasoline or natural gas liquids) shall determine the price permitted to be charged for such products pursuant to paragraph (a) of this section by calculating increased product costs as follows:

(i) With respect to such propane, butane, natural gasoline and natural gas liquids for which separate inventory records are required to be maintained pursuant to § 211.88(c), for each such separate inventory the seller shall make a separate calculation of increased product costs as defined in § 212.92 to be used in determining its selling price for such products pursuant to paragraphs (a) and (b) of this section, with the selling prices of propane included in such products not, however, subject to paragraph (f)(1) of this section. Increased costs so calculated shall not be available for recovery in the prices of other natural gas liquids or other propane, butane or natural gasoline.

(ii) With respect to any quantity of propane, butane, natural gasoline and natural gas liquids for which a separate inventory record is not required to be maintained pursuant to § 211.88(c), the seller shall add the cost of such quantities to the cost of all other quantities of the same product for which separate inventory records are not maintained pursuant to § 211.88(c) or pursuant to § 212.92, in making a separtate calculation of increased product to § 212.92, in making a separate calculation of increased product costs as defined in § 212.92 to be used in determining its selling price for all sales of products other than those maintained in a separate inventory pursuant to § 211.88(c), subject to all other provisions of this section, including paragraph (f)(1).

(g) Special rule of addition to May 15, 1973, prices of unrecouped increased costs of a product in a subsequent month. For covered products other than gasoline, the amount of unrecouped increased product costs calculated and carried forward under paragraph (d) of this section that may be added to the May 15, 1973, selling prices of that product shall be limited to an amount that is not more than:

(i) An amount that, when added to May 15, 1973, selling prices, will provide for the same selling prices for that product in the current month as prevailed at the close of the preceding month, plus

(ii) An amount that, based on estimated sales volumes for each product, will not result in the application to May 15, 1973, selling prices of more than 10 percent of the amount of unrecouped increased costs of product calculated and carried forward under paragraph (e) of this section, as of October 31, 1974, or as of the end of any month thereafter.

(h) Certification. Each seller with respect to each sale of gasoline other than a retail sale must certify in writing to the purchaser the octane number of the gasoline sold.

(i) Reallocation of increased product costs among products. (1) Notwithstanding any other provision of this subpart, increased product costs may be reallocated among products as provided in this paragraph.

(2) Increased product costs may be reallocated only as follows:

(i) General Refinery Products. (A) To the extent that a seller does not allocate its increased product costs for a particular general refinery product, other than propane, to the prices for that product, it may reallocate the unallocated part of its increased product costs for the product to the prices for gasoline or for any other general refinery product (or products) except propane, in whatever amounts the seller deems appropriate. No increased product costs for general refinery products other than propane may be reallocated to the prices for No. 2 oils, for propane, or for aviation jet fuel.

(B) Beginning on April 21, 1976, no increased product costs for No. 1 heating oil, No. 2-D diesel fuel, or kerosene may be reallocated to prices for any covered product.

(C) Beginning on July 1, 1976, no increased product costs for general refinery products other than propane, butane, natural gasoline, natural gas liquids, and aviation gasoline may be reallocated to prices for any other covered period.

(ii) No. 2 oils. (A) To the extent that a seller does not allocate its increased product costs for No. 2 oil to the prices for that prod-

uct, it may reallocate the unallocated part of its increased product costs for that product to the prices for gasoline, in whatever amounts the seller deems appropriate. No increased product costs for No. 2 oils may be reallocated to the prices for any general refinery product or products, including propane, or for aviation jet fuel.

(B) Beginning on April 21, 1976, no increased product costs for No. 2 oils may be reallocated to prices for any covered product.

(iii) Aviation jet fuel. (A) To the extent that a seller does not allocate its increased product costs for aviation jet fuel to the prices for that product, it may reallocate the unallocated part of its increased product costs for that product to the prices for gasoline, in whatever amounts the seller deems appropriate. No increased product costs for aviation jet fuel may be reallocated to the prices for any general refinery product or products, including propane, or for No. 2 oils.

(B) Beginning on September 1, 1976, no increased costs for aviation fuel (naphtha-type) may be reallocated to prices for any covered product.

(iv) Propane. To the extent that a seller does not allocate its increased product costs for propane to the prices for that product, it may reallocate the unallocated part of its increased product costs for that product to the prices for gasoline or for any other general refinery product (or products) or for both or all of them, in whatever amounts the seller deems appropriate. No increased product costs for propane may be reallocated to the prices for No. 2 oils or for aviation jet fuel.

(v) Gasoline. No increased product costs gasoline may be reallocated to the prices for any other covered product.

(3) With respect to each reallocation of increased product costs pursuant to this paragraph, a seller shall:

(i) Determine the increased product cost pursuant to the definition of § 212.92 of the product from which increased product costs are to be reallocated, but without regard to such reallocation, and then adjust downward the amount so determined, for purposes of determining prices of that product, by a per unit amount which is equal to the total dollar amount which is reallocated from such product, divided by the same number of units in inventory as was first used to determine the unadjusted amount of increased product cost of such product, and

(ii) Determine the increased product cost pursuant to the definition of § 212.92 of the product to which increased product costs are to be reallocated, but without regard to such reallocation, which amount may then be adjusted upward, for purposes of determining prices of that product, by a per unit amount which is not more than the total dollar amount, which is reallocated to such product, divided by the same number of units in inventory as was first used to determine the adjusted product cost of such product.

(4) A seller that reallocates increased product costs among products shall maintain records with respect to each such reallocation which are adequate to demonstrate compliance with the requirements of this section.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185, Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[39 FR 1949, Jan. 15, 1974, as amended at 39 FR 7429, Feb. 26, 1974; 39 FR 7796, Feb. 28, 1974; 39 FR 12011, Apr. 2, 1974; 39 FR 39261, Nov. 6, 1974; 39 FR 44411, Dec. 24, 1974; 40 FR 10449, Mar. 6, 1975; 40 FR 40823, Sept. 4, 1975; 40 FR 54565, Nov. 25, 1975; 40 FR 57442, Dec. 10, 1975; 41 FR 1268, Jan. 7, 1976; 41 FR 18305, May 3, 1976; 41 FR 26197, June 25, 1976; 41 FR 30099, July 22, 1976; 41 FR 34008, Aug. 12, 1976; 41 FR 40454, Sept. 2, 1976; 41 FR 41080, Sept. 21, 1976; 42 FR 22133, 22134, May 2, 1977; 42 FR 39197, Aug. 3, 1977; 43 FR 24268, June 5, 1978; 43 FR 60869, Dec. 29, 1978; 44 FR 42545, July 19, 1979; 44 FR 45356, Aug. 1, 1979; 44 FR 60654, Oct. 19, 1979; 44 FR 72567, Dec. 13, 1979; 44 FR 77122, Dec. 28, 1979; 45 FR 1583, Jan. 7, 1980; 45 FR 28304, Apr. 29, 1980; 45 FR 29551, May 2, 1980; 45 FR 36052, May 29, 1980; 45 FR 39241, June 10, 1980; 45 FR 41903, June 23, 1980; 45 FR 72630, Nov. 3, 1980; 45 FR 81009, Dec. 8, 1980]

§ 212.94 Allocated crude pricing.

(a) Scope--(1) General. This section applies to each sale of crude oil made pursuant to the provisions of § 211.65 of Part 211 of this chapter, effective for sales obligations for the allocation periods commencing on or after October 1, 1977.

(2) Definitions. For the purposes of this section--

"High sulfur crude oil" means crude oil the sulfur content of which is equal to or greater than 0.6% (six-tenths of one percent) by weight.

"Low sulfur crude oil" means crude oil the sulfur content of which is less than 0.6% (six-tenths of one percent) by weight.

"Lower forty-eight states" means the forty-eight contiguous states of the United States.

(b) Rule. (1) Notwithstanding the general rules described in this subpart, the price at which low sulfur and high sulfur crude oil, respectively, shall be sold when required pur-

suant to § 211.65 of Part 211 of this chapter shall not exceed the refiner-seller's weighted average per barrel landed cost (as defined in § 212.82, but utilizing the volumes of imported crude oil at the time of importation thereof into the United States), less the average cost of domestic transportation to the refiner-seller's refinery(s), of all low sulfur or high sulfur imported crude oil, respectively (other than crude oil imported from Canada), delivered to the refiner-seller in the month in which the sale is made and the two months preceding that month, plus a handling fee of five cents per barrel, and any transportation, gravity and sulfur content adjustments as specified in paragraphs (2) through (4), respectively, of this paragraph (b). Each refiner-seller making such a sale shall maintain records, which shall be made available to the DOE upon request, listing the volumes and costs of all imported low sulfur and high sulfur crude oil delivered to it.

(2)(i) A price adjustment shall be made for transportation expenses for crude oil offered for sale under § 211.65 of Part 211 of this chapter by adding to the weighted average costs as calculated under paragraph (b)(1) of this section: (A) Where domestic crude oil (other than Alaskan crude oil) is sold, the actual cost of transporting the domestic crude oil from (1) the wellhead, in the event the refiner-seller owns the crude oil so sold or (2) the point of purchase or exchange in the event the refiner-seller acquires the crude oil so sold pursuant to a purchase or exchange, to the refiner-buyer's refinery; (b) where Alaskan crude oil is sold, the actual cost of transporting the Alaskan crude oil from the port of entry into the lower forty-eight states to the refiner-buyer's refinery; (c) where imported crude oil is sold, the actual cost of transporting the crude oil from the U.S. port of entry to the refiner-buyer's refinery.

(ii) For purposes of calculating transportation adjustments under this paragraph (2)(i) a refiner-seller shall include pipeline tariffs, water transportation and terminalling costs, exchange differentials, insurance and taxes paid to deliver the domestic or imported crude oil to the refiner-buyer's refinery.

(iii) Each refiner-seller making a sale of domestic crude oil under § 211.65 of Part 211 of this chapter shall maintain records which shall be made available to the DOE upon request, listing the volumes of domestic crude oil sold, the acquisition cost of such crude oil, and the transportation expenses incurred in transporting the domestic crude oil to the refiner-buyer's refinery.

(3) A price adjustment shall be made for gravity differential of crude oil offered for sale under § 211.65 of Part 211 of this chapter by adding to or substracting from the weighted average costs as calculated under paragraph (b)(1) of this section three cents per barrel for each °API that the crude oil being offered for sale under § 211.65 of Part 211 of this chapter is above or below, respectively, the weighted average °API of imports of crude oil of the same sulfur content category (other than crude oil imported from Canada) for the applicable three month period specified in paragraph (b)(1) of this section for the refiner-seller.

(4) A further price adjustment shall be made for sulfur content differential of crude oil offered for sale under § 211.65 of Part 211 of this chapter by adding to or substracting from the weighted average costs as calculated under paragraph (b)(1) of this section three cents per barrel per one tenth percent that the sulfur content by weight of the crude oil being offered for sale under § 211.65 of Part 211 of this chapter is either below or above, respectively, the percentage representing the weighted average sulfur content of imports of crude oil of the same sulfur content category (other than crude oil imported from Canada) for the applicable three months period specified in paragraph (b)(1) of this section for the refiner-seller.

(5) To calculate a refiner-seller's maximum permitted sale price under paragraph (1) of this paragraph where the refiner-seller receives deliveries of only imported low sulfur crude oil (or only imported high sulfur crude oil) and sells high-sulfur crude oil (or low sulfur crude oil) pursuant to § 211.65 of Part 211 of this chapter, such refiner-seller shall utliize its weighted average per barrel cost of imported crude oil as determined under paragraph (1) of this paragraph for the particular category of crude oil so imported, and apply the gravity and sulfur adjustments specified in paragraphs (3) and (4), respectively, of this paragraph (b).

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, E.O. 11790, 39 FR 23185)

[42 FR 54260, Oct. 5, 1977]

NOTE: The provisions of this section may be affected by Standby Regulation 212-1. Standby Regulation 212-1 appears in Appendix A to Part 212. For the convenience of the user, a table listing all Standby Regulations and sections affected appears in the Finding Aids section of this volume.

§ 212.95 [Revoked]

[45 FR 71767, Oct. 30, 1980]

§ 212.96 Exchanges.

(a) Covered Product Received Pursuant to Exchange Agreements. (1) The unit cost of a covered product received by the seller pursuant to an exchange shall be deemed to be the weighted average unit inventory cost of that product used by the seller to determine its lawful price on the date the product is received by the seller.

(2) Notwithstanding paragraph (a)(1) of this section, where, on the date of receipt of covered product pursuant to an exchange, the inventory volume of purchased product of the type received in the exchange constitutes less than twenty-five percent of the seller's total inventory volume of that product (both purchased and received in exchanges including the exchange in question), the unit cost of the covered product received in the exchange shall be deemed to be the weighted average unit inventory cost attributable to the product given up on the date the covered product is received, multiplied by the volume of product given up, and divided by the volume of the product received in the exchange.

(b) Covered Product Given Up Pursuant to Exchange Agreements. A seller that gives up a quantity or volume of a covered product pursuant to an exchange shall adjust its inventory as if the volume of the product given up had been sold on the date the product is given up, in accordance with generally accepted accounting practices historically and consistently applied by the seller.

(c) Payment and Receipt of Cash Reimbursements Pursuant to Exchanges. Cash reimbursements paid and received with respect to a specific covered product received in an exchange shall respectively be added to or subtracted from non-product cost increases actually incurred, for purposes of determining net increases in non-product costs permitted to be passed through under § 212.93(b). Where the cash reimbursement is not expressly prescribed in a written document signed by both parties to the exchange, a seller shall not adjust the non-product costs attributable to the product received, except that, where a seller gives up an exempt product for a covered product in an exchange and receives a cash payment, the payment must be treated as a reimbursement unless the exchange agreement or other written document signed by both parties substantiates that the payment reflects the market value, differences in the product exchanged on the date the covered product is received. Where a seller gives up an exempt product for a covered product in an exchange and makes a cash payment, the payment will constitute a differential and shall not be treated as an increased non-product cost unless the exchange agreement or other written document signed by both parties specifies the services rendered and that the payment is a cash reimbursement for such services. For purposes of calculating the adjustment to non-product cost under this section, a reimbursement is the dollar amount of a cash payment expressly prescribed in a writing signed by both parties to an exchange, that is made or received by a seller pursuant to an exchange as compensation for costs incurred to transport, store, or perform other services for the other seller pursuant to the exchange. A differential is the cash payment made pursuant to an exchange less any reimbursement.

(d) Recordkeeping. In addition to the reporting requirements prescribed in 10 CFR 210. 92, sellers exchanging products covered under this part shall maintain records for each covered product category for each time period between inventory recalculations under § 212. 93 of (1) the volumes given up and received in exchanges involving a covered product, (2) the cash payments made and received in such exchanges, and (3) copies of any written agreements or other documents pursuant to which the covered products were exchanged.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[43 FR 59822, Dec. 21, 1978]

§ 212.97 Service agreements.

(a) Reseller providing service. The unit cost of a covered product received pursuant to a service agreement by the seller providing the service shall be deemed to be the weighted average unit cost of that product in inventory used by the seller to determine its lawful price on the date the product is received by the seller. The seller that delivers product pursuant to a service agreement shall adjust its inventory as if the volume of the product given up had been sold on the date the product is given up, in accordance with generally accepted accounting practices historically and consistently applied by the seller.

(b) Reseller purchasing service. Cash payments made by a seller with respect to a specific covered product for a service provided under a service agreement shall be reflected in the computation of non-product costs for the period in question, for purposes of determining net increases in non-product costs permitted to be passed through under § 212.93(b).

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[43 FR 59822, Dec. 21, 1978]

APPENDIX A TO SUBPART F OF PART 212

SPECIAL RULE NO. 2--CRUDE OIL ALLOCATION

1. Scope. This Special Rule provides for an alteration in the method of allocated crude oil pricing under § 212.94 effective February 1, 1979.

2. Notwithstanding the general rule described in § 212.94(b)(1), effective February 1, 1979, the price at which low sulfur and high sulfur crude oil, respectively, shall be sold by a refiner-seller, when required pursuant to § 211.65 of Part 211 of this chapter, shall not exceed the refiner-seller's weighted average per barrel landed cost (as defined in § 212.82, but utilizing the volumes of imported crude oil at the time of importation thereof into the United States), less the average cost of domestic transporation to the refiner-seller's refinery(ies) of all low sulfur or high sulfur imported crude oil, respectively (other than crude oil imported from Canada), delivered to the refiner-seller in the month in which the sale is made, plus a handling fee of five cents per barrel, and any transportation, gravity and sulfur content adjustments as specified in paragraphs (2) through (4), respectively, of paragraph (b) of § 212.94. Each refiner-seller making such a sale shall maintain records, which shall be made available to the ERA upon request, listing the volumes and costs of all imported low sulfur and high sulfur crude oil delivered to it.

3. Provisions of Subpart F. The provisions of Subpart F of Part 212 shall remain in full force and effect except as expressly modified by the provisions of this Special Rule.

[44 FR 9375, Feb. 13, 1979]

Subpart G--[Reserved]

Subpart H--New Items

§ 212.111 New item and new market rule.

(a) New item. (1) An item is a new item if--(i) The firm concerned did not produce or sell it in the same or substantially similar form at any time during the one-year period immediately preceding the day on which the firm offers it for sale. (A change in appearance, arrangement, or combination including a change in octane number does not create a new item. Ordinarily a change in fashion, style, form or packaging does not create a new item); and

(ii) It is substantially different in purpose, function, quality, or technology, or its use or service effects a substantially different result from any other item which the firm concerned currently sells or sold at any time during the 1-year period immediately preceding the first date on which the firm offers it for sale.

(2) New market. An item which the firm concerned has previously sold is a new item with respect to its offer for sale to any market to which it did not sell it at any time during the 1-year period immediately preceding the first date on which the firm offers it for sale. For purposes of this section, a "market" is one or more members of any one of the following groups; resellers; retailers; consumers; manufacturers; or service organizations.

(b) Base price determination--(1) Refiners. (i) A refiner in existence on May 15, 1973, which offers a new item shall determine the base price for that item pursuant to the base price provisions of § 212.82(b). However, for purposes of determining the price at which the item was lawfully priced in transactions on May 15, 1973, the refiner shall use the average price received on May 15, 1973, for the same or most nearly similar item sold to the same market by other refiners selling the same or most nearly comparable item in the same marketing area.

(ii) A refiner coming into existence after May 15, 1973, which offers a new item shall determine the base price for that item pursuant to the base price provisions of § 212.82(b). However, for purposes of computing the base price, the increase product costs shall be calculated using the cost of the item first offered for sale rather than the May 1973 cost for the item, and the price at which that item is priced in transactions by other refiners selling the same or most nearly comparable item in the same marketing area on the day when the item is first offered for sale shall be used rather than the May 15, 1973, selling price.

(2) [Reserved]

(3) Resellers. A reseller, reseller-retailer or retailer, offering a new item, shall for purposes of applying the price rule of § 212.93 determine the May 15, 1973, selling price for that item as the price at which that item is priced in transactions at the nearest comparable outlet on the day when the item is first offered for sale. For purposes of computing the "increased costs," the cost of the item first offered for sale shall be used rather than the May 15, 1973 cost.

(c) Base prices and base production control

levels upon acquisition. (1) If a legal entity or a component of a legal entity determines a base price or maximum selling price, or ceiling price pursuant to this part for a covered product which it sells to a particular market and the entity, or component is subsequently acquired by another firm, that covered product does not become a new item with respect to the same market. The base price or ceiling price of the covered product with respect to that market remains the base price or ceiling price determined for it by the acquired entity or component.

(2) If a legal entity or component of a legal entity determines pursuant to this part a base production control level for a property which produces domestic crude petroleum and the entity or component is subsequently acquired by another firm the domestic crude oil produced from that property does not become new crude oil. The base production control level for that property remains the base production control level determined for it by the acquired entity or component.

(d) Quarterly reporting of new items. A firm subject to the quarterly reporting requirements of Subpart I of this part and which has projected sales and revenues for its current fiscal year of $10 million or more derived from the sale of new items shall, in accordance with instructions which accompany forms issued pursuant to Subpart I of this part, provide information which demonstrates that, with respect to each new item with projected annual sales of $1 million or more which is offered for sale for the first time during the quarter concerned, the item qualifies as a new item as defined in this section and the base price of that item has been determined in accordance with this section.

(Federal Energy Administration Act of 1974, Pub. L. 93-275; E.O. 11790, 39 FR 23185)

[39 FR 1949, Jan. 15, 1974, as amended at 39 FR 6532, Feb. 20, 1974; 39 FR 42374, Dec. 5, 1974; 40 FR 60038, Dec. 31, 1975]

§ 212.112 Unleaded gasoline.

(a) Scope. This section prescribes the method for calculating the maximum price which may be charged in sales of unleaded gasoline by all refiners, and by resellers, reseller-retailers and retailers which did not sell unleaded gasoline on May 15, 1973, or within the 30-day period prior thereto.

(b) Rule. Notwithstanding the provisions of § 212.111, a firm offering for sale after June 30, 1974, gasoline which is unleaded gasoline as described by the Environmental Protection Agency (40 CFR Chapter I, Part 80), shall determine prices of that item in accordance with the provisions of Subpart E or Subpart F of this part, as appropriate, provided, however, that:

(1) For purposes of determining the weighted average price at which unleaded gasoline was lawfully priced in transactions with the class of purchaser concerned on May 15, 1973, in order to calculate the "maximum allowable price" as defined in § 212.82 a refiner shall use either a price not in excess of the weighted average price at which leaded gasoline of the same or nearest octane number was lawfully priced by it in transactions with that class of purchaser on May 15, 1973, computed in accordance with the provisions of § 212.83(a), plus 1 cent per gallon; or the weighted average price at which unleaded gasoline was lawfully priced in transactions with the class of purchaser concerned on May 15, 1973, computed in accordance with the provisions of § 212.83(a); and

(2) For purposes of determining, under § 212.93(a), the weighted average price at which unleaded gasoline was lawfully priced by the seller in transactions with the class of purchaser concerned on May 15, 1973, a reseller, reseller-retailer, or retailer shall use a price not in excess of the weighted average price at which leaded gasoline of the same or nearest octane number was lawfully priced by it in transactions with that class of purchaser on May 15, 1973; and

(3) For purposes of computing under § 212.92 the "increased costs" of unleaded gasoline, a reseller, reseller-retailer, or retailer shall use the difference between the weighted average unit cost of unleaded gasoline in inventory and the weighted average unit cost of leaded gasoline of the same or nearest octane number in inventory on May 15, 1973.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974; Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-485; E.O. 11790, 39 FR 23185)

[39 FR 24924, July 8, 1974 as amended at, 39 FR 26286, July 18, 1974; 39 FR 42374, Dec. 5, 1974; 42 FR 5031, Jan. 27, 1977]

Subpart I—Prenotification and Reporting

§ 212.126 Reports.

(a) Producers. (1) Each firm which produces as an operator domestic crude oil and which derives $50 million or more in annual sales or revenues from sales of covered products shall prepare and file with DOE periodic reports in accordance with forms and instructions issued by DOE.

(2) Each firm which produces as an operator

domestic crude oil from a property and which sells the domestic crude oil above the ceiling price calculated pursuant to § 212.73 shall prepare and file with the DOE periodic reports in accordance with the forms and instructions issued by the DOE.

(b) Refiners, retailers, and resellers. Each firm which refines covered products and each firm which derives $50 million or more in annual sales or revenues from the retailing or reselling of covered products shall prepare and file with the DOE periodic reports in accordance with forms and instructions issued by DOE. Each refiner shall submit its calculations under the formulas of § 212.83 in accordance with forms and instructions issued by DOE.

(c) No. 2 heating oil sellers. Any seller of No. 2 heating oil which increases the price of No. 2 heating oil pursuant to Subpart E or F must submit a report in accordance with the forms and instructions issued by the DOE by the fifth day following the date on which the price is increased.

(d)(1) Resubmissions and refiling of reports by refiners. A refiner shall exercise due care and diligence in the preparation of cost allocation reports filed pursuant to this section. DOE will routinely accept resubmissions or refiling of such reports only within one year after the original filing or submission. Any entry contained in an otherwise timely report which purports to change or adjust retroactively an entry or allocation contained in a report previously filed or submitted shall be considered a refiling or resubmission for purposes of this paragraph and will not be given force or effect absent compliance with the provisions of this paragraph.

(2) Exceptions. Notwithstanding the provisions of paragraph (d)(1) of this section, a refiner may resubmit or refile reports until June 1, 1979, for months of measurement beginning with September 1973; where expressly authorized by DOE regulation or order; or where DOE grants written permission to resubmit or refile for good cause shown.

(3) Applications to resubmit or refile. In any application for permission to resubmit or refile a report pursuant to paragraph (d)(2) of this section, DOE will not make a finding of good cause routinely. Where it appears that such a finding may adversely affect the interest of the consuming public, a firm must demonstrate in its application, at a minimum, that the claimed errors or omissions in the report or reports which the firm seeks to replace or modify did not result from a failure to exercise due care and diligence. Firms must apply for permission pursuant to paragraph (d)(2) of this section, in writing, to the DOE Office of Special Counsel for Compliance or Office of Enforcement, as appropriate. Applications to resubmit or refile must be accompanied by a written statement completely describing the proposed adjustments and the reasons therefor, and a numerical schedule which reflects both the previously submitted figures and the proposed adjusted figures. The appropriate DOE Office will dispose of each application in writing, with a concise statement of the reasons for granting or denying the application. The disposition of such an application shall be subject to appeal as an order under Subpart H of Part 205.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, and Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94385, and Pub. L. 95-70; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[39 FR 1949, Jan. 15, 1974, as amended at 39 FR 7582, Feb. 27, 1974; 44 FR 14536, Mar. 13, 1979]

§ 212.127 Manner of reporting.

(a) Each report required under § 212.126 of this secion shall be made by the parent in accordance with forms and instructions issued by the DOE.

(b) In filing reports pursuant to § 212.126, a parent shall submit data jointly for itself and its consolidated entities and separately for each unconsolidated entity having $10 million or more in annual sales or revenues.

§ 212.128 Recordkeeping.

(a) Producers of crude oil. Each producer of crude oil shall, with respect to each property, prepare and maintain at its principal place of business, (1) a reasonable description of the property concerned, (2) a statement of the property's base production control level and how determined, and (3) documentation of the highest posted prices used to determine any sales of upper and lower tier crude oil from the property, specifying the reference field and posting and the basis for its selection. Each producer of crude oil shall, with respect to any stripper well property, prepare and maintain at its principal place of business, records on a well-by-well basis, of production, including records to indicate each time that production was significantly curtailed by reason of mechanical failure, or other disruption in production, for the period during which the property qualified as a stripper well lease. Each producer of crude oil shall, with respect to any property from which it sells market level new crude oil, prepare and maintain at its principal place of business records as to

amounts of market level new crude oil sold from that property during any particular month and the names and addresses of each purchaser of such crude oil and the amounts of such crude oil that each purchased.

(b) Resellers and Retailers. Each firm which derives less than $50 million but more than $1 million in annual sales or revenues from the retailing or reselling of covered products shall prepare and maintain at its principal place of business periodic reports in accordance with forms and instructions issued by the DOE.

(c) Marginal properties. Each producer of crude oil from a marginal property shall, with respect to the qualifying period, maintain at its principal place of business, (1) records specifying the number of wells on the property, (2) adequate records or a certification by a registered petroleum engineer, providing the completion depths of each well, and (3) records providing the volumes of crude oil produced at each depth. Where actual volumes are unavailable, estimates verified by a registered petroleum engineer will be required to be maintained. Access to such records, with adequate opportunity for duplication by DOE, will immediately be provided to the DOE upon request of DOE audit personnel.

(d) Producers of newly discovered crude oil--(1) Records. Each producer of crude oil shall, with respect to each newly discovered crude oil property or each unitized property from which newly discovered crude oil is imputed, prepare and maintain records that provide a reasonable description of the property concerned and the basis on which it determined the property to be a newly discovered crude oil property or eligible to have newly discovered crude oil imputed. These records should include the following information:

(i) A detailed description of the property or the unitized property, including--

(A) The lease name, the operating number, the state-supplied identification number, and all other information that uniquely describes the property or the unitized property;

(B) The exact geographical location of the property or the unitized property;

(C) A copy of the original lease or farm-out assignment and copies of all amendments, restrictions, extensions and revisions of the original lease or farm-out assignment or any other applicable legal instrument concerning the right to produce;

(D) Where either a drilling unit or any other unit has been formed, a copy of the unitization agreement;

(E) Where the property or the unitized property has been defined as a part of a larger lease tract, the area limits of the property and supporting documentation for such a definition;

(F) Where the property is a reservoir that is to be or has been certified as a newly discovered crude oil property, a description of the reservoir designation by the appropriate governmental regulatory authority and the basis upon which the reservoir qualifies together with supporting documentation;

(G) Where applicable on either a depth or a formation basis, the vertical or geological limits of the property or the unitized property and supporting documentation for such a definition;

(H) Where newly discovered crude oil is imputed from a unitized property, a description of that part of the unitized property that qualifies for such treatment and the basis on which it qualifies together with supporting documentation; and

(ii) The records of production from the property or the unitized property, including--

(A) The date drilling or reworking of the controlling initial well was commenced;

(B) A record of the drilling and the date the controlling initial well was completed or recompleted;

(C) The date of the first production and sale of crude oil from the property;

(D) The date of installation of production facilities (such as a tank battery, a hook-up to a pipeline or a gathering system) for the property;

(E) The date of the first production and sale of crude oil in commercial quantities from the property;

(F) The name of the initial first purchaser of crude oil from the property;

(G) The name of the initial first purchaser of crude oil produced in commercial quantities from the property or imputed newly discovered crude oil from the unitized property;

(H) Where the property or the unitized property produced crude oil before but not during calendar year 1978 and for which crude oil production was reestablished after December 31, 1978, the date of the last production before calendar year 1978.

(2) Failure to grant access to records. Notwithstanding the provisions of § 212.79 and of § 212.131, a producer may not obtain prices exempt from the ceiling price limitations of Subpart D of this part, for crude oil produced and sold from a newly discovered crude oil property or from a unitized property from which newly discovered crude oil is imputed, during any month that it fails to provide DOE with access at a single location to records required by this paragraph (d) within 20 working days of the date of receipt of a request by DOE. DOE may permit a producer more than 20 working days in which to assemble and provide access to the records required by this paragraph (d).

(e) Producers of heavy crude oil. Each producer of heavy crude oil or imputed heavy crude oil shall, with respect to each property from which it produces heavy crude oil or imputed

heavy crude oil, prepare and maintain at its principal place of business, (1) a reasonable description of the property concerned and (2) the basis on which it determined the property to be a heavy crude oil property or eligible to have heavy crude oil imputed. Each producer of heavy crude oil which injects a diluent into a particular heavy crude oil property shall prepare and maintain records as to the amounts of diluent injected into that property and the dates of any such injections.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-385; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385; E.O. 11790, 39 FR 23185; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[41 FR 4941, Feb. 3, 1976, as amended at 44 FR 25169, Apr. 27, 1979; 45 FR 78595, Nov. 25, 1980]

§ 212.129 Price and octane number information and posting.

(a) Each seller of covered products shall maintain records of its base production control levels and selling prices authorized pursuant to this part and shall make such information available upon request by a customer.

(b) Each retail seller of gasoline shall comply with subparagraph (1) or, in the alternative, subparagraph (2), of this paragraph.

(1) Each retail seller of gasoline shall post and maintain in legible form the maximum lawful selling price of each type and grade of gasoline. The maximum lawful selling price shall be posted either: (i) On each pump used to dispense gasoline at retail outlets in numbers not less than one-half (1/2) inch high facing each direction from which the pumps are generally viewed by customers, or (ii) at a prominent location which is easily visible (in numbers not less than four (4) inches high) to a customer purchasing gasoline at the retail outlet. The posting of the actual selling price is not considered to be the posting of the maximum lawful selling price as required by this subparagraph. Whenever an adjustment is made to the maximum lawful selling price, each retail seller must post the new adjusted maximum lawful selling price, and remove the prior posted price.

(2) Each retail seller of gasoline shall post and maintain in legible form a certification that the maximum lawful selling price for a particular type or grade of gasoline has been calculated by the retail seller and that the actual selling price for that type or grade of gasoline is either equal to or less than its maximum lawful selling price. Such certification shall be placed either: (i) On each pump used to dispense gasoline at the seller's retail outlet in letters not less than one-half (1/2) inch high, facing each direction from which the pumps are generally viewed by customers, or (ii) at a prominent location which is easily visible (in letters not less than one and one-half (1 1/2) inches high) to customers purchasing gasoline at the seller's retail outlet.

(c) Each refiner of gasoline must, with respect to each sale of gasoline other than a retail sale, certify in writing to the purchaser the octane number, as defined in § 212.31, of the gasoline sold.

(d) The maximum lawful selling price may, at the discretion of DOE, be decreased by five (5) cents per gallon for each day of failure to comply with § 212.129(b), plus an additional 30 days.

(Emergency Petroleum Allocation Act of 1973, 15 U.S.C. § 751 et seq., Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, 15 U.S.C. § 787 et seq., Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, and Pub. L. 95-91; Energy Policy and Conservation Act, 42 U.S.C. § 6201 et seq., Pub. L. 94-163, as amended, Pub. L. 94-385, and Pub. L. 95-70; Department of Energy Organization Act, 42 U.S.C. § 7101 et seq., Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[39 FR 1949, Jan. 15, 1974, as amended at 40 FR 6324, Feb. 11, 1975; 41 FR 15339, Apr. 12, 1976; 44 FR 45357, Aug. 1, 1979; 44 FR 61171, Oct. 24, 1979]

§ 212.130 Effect of failure to file or maintain reports or other documents required by or under certain sections of this part.

(a) If a firm which is required to file a report or other document with the Department of Energy pursuant to the provisions of this part or an order issued by the Department of Energy does not, within the time limits prescribed, file the report or other document—

(1) The firm may not implement any further price increases including price increases which could otherwise be implemented pursuant to § 212.125 until it has complied with that reporting requirement and has obtained the special approval of the Department of Energy.

(2) Except to the extent specifically authorized otherwise by the DOE in any case, based upon a written request of the firm concerned citing hardship or inequity, action is sus-

pended on all requests for exception filed by that firm until it has complied with the reporting requirement; and

(3) The DOE may, whenever it considers it appropriate under the circumstances, order the firm to reduce any of its prices.

(b) Each day that a firm fails to comply with a reporting requirement pursuant to this part pertaining to reports, or with an order under this part, is considered to constitute a separate violation of this part or that order.

§ 212.131 Certification of domestic crude oil sales.

(a)(1) Stripper well properties. With respect to each stripper well property, the producer shall certify in writing once to each purchaser of crude oil produced from that property:

(i) That the property concerned has qualified as a stripper well property; and

(ii) The average daily production per well for the 12-month period during which the property qualified as a stripper well property.

(2) Newly discovered crude oil properties. With respect to each newly discovered crude oil property, the producer shall certify in writing once to each purchaser of crude oil produced from that property that the property concerned has qualified as a newly discovered crude oil property.

(3) Heavy crude oil properties. With respect to each heavy crude oil property, the producer shall certify in writing once to each purchaser of crude oil produced from that property that the property concerned has qualified as a heavy crude oil property.

(4) Other properties. (i) With respect to each sale of crude oil from a property (other than a stripper well property, a newly discovered crude oil property, or a heavy crude oil property), the producer shall certify in writing to each purchaser the number of barrels, if any, of--

(A) Lower-tier ("old") crude oil (separately identifying any California lower-tier crude oil, as defined in § 211.62 of Part 211 of this chapter, and the gravity in degrees API of such California lower-tier crude oil at the time of the sale);

(B) Upper-tier ("new") crude oil (separately identifying any California upper-tier crude oil, as defined in § 211.62 of Part 211 of this chapter, and the gravity in degrees API of such California upper-tier crude oil at the time of the sale), excluding any crude oil transported through the trans-Alaska pipeline;

(C) Crude oil transported through the trans-Alaska pipeline (separately identifying ANS upper-tier crude oil and ANS crude oil that is not subject to the ceiling price limitations of this Part);

(D) Incremental tertiary crude oil as determined pursuant to § 212.78;

(E) Tertiary incentive crude oil as determined pursuant to § 212.78;

(F) Market level new crude oil as determined pursuant to § 212.74;

(G) Imputed stripper well crude oil determined pursuant to § 212.75(b);

(H) Imputed newly discovered crude oil determined pursuant to § 212.75(b);

(I) Imputed heavy crude oil determined pursuant to § 212.75(b); and

(J) Other domestic crude oils, the first sale of which is exempt from Part 212.

(ii) With respect to each property which has not been certified to a purchaser as a stripper well property, a newly discovered crude oil property, or a heavy crude oil property, the producer shall certify in writing once to each purchaser of crude oil produced and sold from that property;

(A) The highest posted price at 6 a.m., local time, May 15, 1973, for transactions in that grade of crude oil in that field, or if there was no posted price in that field for that grade of domestic crude oil, the related price for that grade of domestic crude oil which is most similar in kind and quality in the nearest field for which prices were posted; and

(B) The highest posted price on September 30, 1975, for transactions in that particular grade of crude oil in that field in September 1975, or if there was no posted price in that field for that grade of domestic crude oil, the related price for that grade of domestic crude oil which is most similar in kind and quality in the nearest field for which prices were posted.

(5) One-Time certifications. (i) Except as provided for in paragraphs (a)(5) (ii) and (iii) of this section, with respect to any property (except a unitized property) from which crude oil is sold to only one purchaser, the requirements of paragraph (a)(4)(i) of this section may be complied with by a one-time written certification to the purchaser of the property's monthly base production control level determined pursuant to § 212.72, whether based upon production and sale of crude oil in 1972 or upon production and sale of old crude oil in 1975, or upon production and sale of old crude oil during the six-month period ending March 31, 1979, and, if applicable, either the property's adjusted base production control level determined pursuant to § 212.76 or the information necessary to compute such adjusted base production control level pursuant to § 212.76.

(ii) Except as provided for in paragraph (a)(5)(iii) of this section, with respect to any unitized property for which the producer has determined a unit base production control level and from which crude oil is sold to only one purchaser, the requirements of paragraph (a)(4)(i) of this section may be complied with

by a one-time written certification to the purchaser of--

(1) The monthly unit base production control level, determined pursuant to § 212.75(b);

(2) The number of barrels of "imputed new crude oil," if any, determined pursuant to § 212.75(b), excluding any crude oil transported through the trans-Alaska pipeline;

(3) The number of barrels of crude oil transported through the trans-Alaska pipeline (separately identifying ANS upper-tier crude oil and ANS crude oil that is not subject to the ceiling price limitations of this part), if any;

(4) The number of barrels of imputed newly discovered crude oil, if any, determined pursuant to § 212.75(b);

(5) The number of barrels of imputed stripper well crude oil, if any, determined pursuant to § 212.75(b); and

(6) The number of barrels of imputed heavy crude oil, if any, determined pursuant to § 212.75(b).

(iii) Notwithstanding the provisions of paragraphs (a)(5)(i) and (ii) of this section, a producer shall certify in writing to each purchaser: (A) In each sale the amounts and gravity of California lower-tier crude oil and California upper-tier crude oil; (B) in each sale the amount of crude oil that is being sold as tertiary incentive crude oil pursuant to § 212.78(a)(2) and shall identify whether this amount would have been lower-tier crude oil or upper-tier crude oil except for its certification as tertiary incentive crude oil; and (C) once, if tertiary incremental crude oil may be sold from a property pursuant to § 212.78(a)(1), the amounts of non-incremental crude oil production from that property for each month, as determined pursuant to § 212.78.

(iv) With respect to U.S.-owned crude oil sold pursuant to the Naval Petroleum Reserves Production Act of 1976 (Pub. L. 94-258), the producer may comply with the requirements of paragraph (a)(4)(i) by certifying in writing once to each purchaser of such crude oil produced and sold from a property that the first sale of such crude oil from that property is exempt from the provisions of this Part.

(6) Time of certifications. Certifications required or authorized by this paragraph (a) to be made once shall be made within the consecutive two-month period immediately following the first month that the oil in question is produced and sold. Certifications required by this paragraph (a) to be made with respect to each sale shall be made within the consecutive two-month period immediately following the month in which that sale is made. After the close of the two-month period immediately succeeding the month in which crude oil is produced and sold, no certification, other than a certification for lower-tier ("old") crude oil, shall be effective with respect to the purchaser of that crude oil, except where such certification explicitly is required or permitted by DOE order, interpretation or ruling.

(b)(1) Reseller certification. Each seller of domestic crude oil, other than a producer of domestic crude oil covered by paragraph (a) of this section, shall, with respect to each sale of domestic crude oil other than an allocation sale pursuant to § 212.65 of Part 211, or a sale in which no volumes of domestic crude oil are deemed to have been transferred pursuant to § 211.67(g) of Part 211, certify in writing to the purchaser (i) that the price charged for the domestic crude oil is not greater than the maximum price permitted pursuant to this part and (ii) the respective volumes of and respective per barrel prices for the--

(A) Lower-tier ("old") crude oil (separately identifying any California lower-tier crude oil, as defined in § 211.62 of Part 211 of this chapter, and the gravity in degrees API of such California lower-tier crude oil at the time of the sale);

(B) Upper-tier ("new") crude oil (separately identifying any California upper-tier crude oil, as defined in § 211.62 of Part 211 of this chapter, and the gravity in degrees API of such California upper-tier crude oil at the time of the sale), exclusive of any crude oil transported through the trans-Alaska pipeline;

(C) Crude oil transported through the trans-Alaska pipeline (separately identifying ANS upper-tier crude oil and ANS crude oil that is not subject to the ceiling price limitations of this part);

(D) Stripper well crude oil;

(E) Incremental tertiary crude oil;

(F) Tertiary incentive crude oil;

(G) Newly discovered crude oil;

(H) Market Level new crude oil;

(I) Heavy crude oil; and

(J) Other domestic crude oils the first sale of which is exempt from the provisions of this part--included in the volume of domestic crude oil so sold.

(2) Time of certifications. Each seller of domestic crude oil, other than a producer of domestic crude oil, shall make the certification required by this paragraph as soon as practicable after receipt of the required certifications from its sellers, but in no event later than 30 days following such receipt. However, if the domestic crude oil is not sold until after the expiration of the thirty-day period, the certification required by this paragraph shall be made within ten days following the sale of the domestic crude oil.

(3) Actual volumes. All certifications required by this paragraph shall relate only to the actual volumes of crude oil included in any mixed blend of crude oil and other refined petroleum products and residual fuel oil.

(c) Certification required for purchase or sale of crude oil. No firm may sell domestic

crude oil unless it provides the certification required by this section. No firm may knowingly purchase domestic crude oil for which there is no certification as required by this section; Provided, however, That the provisions of this paragraph do not apply to the sale of domestic crude oil to a firm under circumstances of economic or other coercion in which the buyer, because of its need for crude oil had no reasonable alternative but to purchase the domestic crude oil for which there is no certification, and such firm promptly reports the purchase to the Department of Energy for investigation.

(d) Form of certification. All certifications required by this section shall be in writing, either upon an invoice or billing or by separate instrument, and shall be effective only when delivered to and received by the purchaser of domestic crude oil.

(Emergency Petroleum Allocation Act of 1973, 15 U.S.C. 751 et seq., Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, 15 U.S.C. 787 et seq., Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, and Pub. L. 95-91; Energy Policy and Conservation Act, 42 U.S.C. 6201 et seq., Pub. L. 94-163, as amended, Pub. L. 94-385, and Pub. L. 95-70, Pub. L. 95-619, and Pub. L. 96-30; Department of Energy Organization Act, 42 U.S.C. 7101 et seq., Pub. L. 95-91, Pub. L. 95-509, Pub. L. 95-619, Pub. L. 95-620, and Pub. L. 95-621; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[41 FR 36184, Aug. 26, 1976, as amended at 41 FR 37310, Sept. 3, 1976; 41 FR 43394, Oct. 1, 1976; 42 FR 62903, Dec. 14, 1977; 42 FR 64864, Dec. 29, 1977; 43 FR 33691, Aug. 1, 1978; 44 FR 25170, Apr. 27, 1979; 44 FR 25832, May 2, 1979; 44 FR 51157, Aug. 30, 1979; 44 FR 65723, Nov. 14, 1979; 45 FR 21209, Apr. 1, 1980; 45 FR 46760, July 10, 1980; 45 FR 78596, Nov. 25, 1980]

§ 212.132 Records on sequence of cost recoupments.

(a) Refiners. Refiners are required to calculate and keep records as of the last day of each calendar month for each product or group of products represented by the symbol "i" in the formulae contained in § 212.83(c) of what amount of each of the types of costs set forth in § 212.83(f) were used in computing prices for that month, and of the allocation of increased product costs to propane pursuant to § 212.83(c)(1)(iii)(A).

(b) Refiners that are also processors of natural gas. Refiner processors are required to calculate and keep records as of the last day of each calendar month of what amount of each of the types of costs set forth in § 212.83(f) were used in computing prices for that month, and of the allocation of increased product costs to propane pursuant to § 212.83(c)(iii)(A).

[41 FR 15340, Apr. 12, 1976]

§ 212.133 Certification of SPR Crude Oil.

When proposals are submitted and when crude oil is delivered to the Government for storage in the Strategic Petroleum Reserve, offerors and sellers shall certify what volumes of crude oil are lower-tier, upper-tier, or imported or domestic uncontrolled crude oil and shall certify the ceiling or other maximum lawful price, if any, applicable to the volumes so classified.

[45 FR 71767, Oct. 30, 1980]

Subpart J—[Reserved]

Subpart K—Natural Gas Liquids

AUTHORITY: Emergency Petroleum Allocation Act of 1973, Pub L. 93-159; Federal Energy Administration Act of 1974, Pub. L. 93-275; E.O. 11790, 39 FR 23185.

SOURCE: 39 FR 44412, Dec. 24, 1974, unless otherwise noted. Redesignated at 40 FR 6200, Feb. 10, 1975.

NOTE: A class exception document relating to the retroactive application of the price rules of Subpart K was published at 40 FR 40824, Sept. 4, 1975.

§ 212.161 Applicability and relationship to other subparts.

(a) Scope. This subpart applies to all sales of natural gas liquids and natural gas liquid products, including transfers between affiliated entities, by all firms, including gas plant operators, producers of natural gas, natural gas royalty owners, and refiners, except that this subpart does not apply to sales by resellers or retailers subject to Subpart F of this part. This subpart does not apply to sales of lease or plant condensate which is defined as crude oil under § 212.31.

(b) Relationship to other subparts.—(1) Gas plant operators. Refiners that only refine liquid hydrocarbons from oil and gas field gases and do not refine crude oil shall determine their maximum lawful prices pursuant to this Subpart K and are not also subject to Subpart E.

(2) Crude oil refiners which are also gas plant operators—(i) General. Refiners that refine liquid hydrocarbons from oil and gas

field gases, and also refine crude oil, shall determine their May 15, 1973, selling prices and increased product and processing costs for natural gas liquids and natural gas liquid products produced in gas plants pursuant to this subpart, but shall determine their maximum lawful selling prices pursuant to Subpart E.

(ii) Calculation of increased product costs. Such refiners shall calculate the increased product costs of all natural gas liquids and the increase product costs attributable to natural gas liquid products pursuant to §§ 212.167 and 212.168, and shall add the amount of increased product costs so determined to the amount of increased product costs incurred in each month of measurement and determined to be allocable to the appropriate product category under the refiner's cost allocation formulae of § 212.83(c)(1): Provided, That the amount of such increased product costs allocable to propane prices is limited pursuant to the provisions of § 212.168(c) and § 212.83(c)(1)(ii)(F).

(iii) Calculation of increased processing costs. Such refiners shall calculate increased processing costs attributable to natural gas processing pursuant to § 212.165, and shall add the amount of increased processing costs so determined to the amount of increased non-product costs attributable to refinery operations incurred in each month of measurement and determined to be allocable to prices charged for covered products pursuant to the formulae in § 212.83(c).

(iv) Calculation of increased marketing costs. Such refiners shall calculate allowable increased marketing costs pursuant to § 212.83.

(c) Sales of ethane. This subpart does not apply to sales of ethane.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332; Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, E.O. 11790, 39 FR 23185; Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

[39 FR 44412, Dec. 24, 1974. Redesignated and amended at 40 FR 6200, Feb. 10, 1975; 41 FR 9088, Mar. 3, 1976; 41 FR 15340, Apr. 12, 1976]

§ 212.162 Definitions.

For purposes of this subpart—

"Cost of natural gas shrinkage" means the reduction in selling price per thousand cubic feet (MCF) of natural gas processed, which is attributable to the reduction in volume or BTU value of the natural gas resulting from the extraction of natural gas liquids, as determined pursuant to the contract in effect at the time for which cost of natural gas shrinkage is being measured, and under which the processed natural gas is sold.

"Firm" means a parent and the consolidated and unconsolidated entities (if any) which it directly or indirectly controls.

"First sale" means, with respect to natural gas liquids or natural gas liquid products, the first transfer for value to a class of purchaser for which a fixed price per unit of volume is determined.

"Gas plant" means a facility in which natural gas liquids are separated from natural gas, or in which natural gas liquids are fractionated or otherwise separated into natural gas liquid products, or both. For purposes of computing increased processing costs under § 212.165, and for purposes of determining the eligibility of production from a plant to receive the prices specified in § 212.164(e), a "gas plant" includes any natural gas or natural gas liquid gathering facilities and the transportation lines (including compression stations) connecting these facilities to the actual physical plant at which the natural gas or natural gas liquids are processed: Provided, That natural gas gathering facilities and related transportation lines shall be considered a part of a gas plant for these purposes only if the first seller of the natural gas liquids or natural gas liquid products produced in the plant has no beneficial interest in the residue gas from the plant.

"Gas plant operator" means any firm, including a gas plant owner, which operates a gas plant and keeps the gas plant records.

"Gas plant owner" means any firm with an ownership interest in a gas plant.

"Groundbreaking" means the date on which the actual physical construction of a gas plant is undertaken.

"Natural gas liquids" means a mixed hydrocarbon stream containing, in whole or in substantial part, mixtures of ethane, butane (isobutane and normal butane), propane or natural gasoline.

"Natural gas liquid products" means the separate products derived from natural gas liquids, including butane (iso-butane and normal butane), propane, propane-butane mixtures, and natural gasoline, but not ethane.

"Net-back sale" means, with respect to natural gas liquids, any transfer for value to a class of purchaser for which a percentage of the revenues from the first sale of natural gas liquids or natural gas liquid products is received.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended Pub. L. 93-511, Pub.

L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332; Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, E.O. 11790, 39 FR 23185; Energy Organization Act, E.O. 12009, 42 FR 46267)

[39 FR 44412, Dec. 24, 1974. Redesignated at 40 FR 6200, Feb. 10, 1975, and amended at 43 FR 43000, Sept. 21, 1978]

§ 212.163 General price rule.

(a) First sale. A royalty owner, producer, gas plant owner, gas plant operator or other entity may not charge to (or receive from) any class of purchaser a price in excess of the weighted average price at which natural gas liquids or natural gas liquid products were lawfully priced in transactions with the class of purchaser concerned on May 15, 1973, except to the extent permitted by this subpart.

(b) Net-back sale. A royalty owner, producer, gas plant owner, gas plant operator, or other entity that transferred natural gas liquids or natural gas liquid products to any class of purchaser on May 15, 1973, in a net-back sale shall not charge (or receive) per gallon revenues for such natural gas liquids or natural gas liquid products in excess of the per gallon revenues received in such net-back sales on May 15, 1973, except to the extent that the first sale price upon which the net-back amount is determined is permitted to increase above its May 15, 1973, level pursuant to this subpart, and except to the extent that the method for determining the amount of the net-back is changed, provided, however, that any change in the method of determining the amount of any net-back shall not constitute an increased product cost or an increased non-product cost.

§ 212.164 Adjusted May 15, 1973, first sale price.

(a) Natural gas liquid products. For purposes of determining lawful prices of natural gas liquid products in a first sale pursuant to this subpart, a firm may use, in lieu of the weighted average price at which natural gas liquid products were lawfully priced in first sale transactions with a class of purchaser on May 15, 1973, prices of not more than $.085 per gallon for propane, not more than $0.09 per gallon for butane, and not more than $.10 per gallon for natural gasoline.

(b) Natural gas liquids. For purposes of determining lawful prices of natural gas liquids in a first sale, if the first sale price of natural gas liquids on May 15, 1973, represented a discount from the lawful first sale prices of natural gas liquid products at the nearest sales point for such products on that date, a firm may use, in lieu of the actual May 15, 1973, first sale prices of natural gas liquids, first sale prices of natural gas liquids computed on the basis of not more than $.085 per gallon for the propane content, not more than $.09 per gallon for the butane content, and not more than $.10 per gallon for the natural gasoline content, provided that the natural gas liquids first sale prices thus computed shall be reduced by the same percentage discount from the adjusted first sale prices for the component natural gas liquid products as the actual May 15, 1973, first sale prices of natural gas liquids were reduced from the actual May 15, 1973, selling prices of natural gas liquid products at the nearest sales point of the natural gas liquids purchaser for such products.

(c) Imputed May 15, 1973, first sale prices for natural gas liquid products from new gas plants where groundbreaking did not occur until January 1, 1975, or thereafter. For purposes of determining lawful prices of natural gas liquid products produced in a gas plant where groundbreaking did not occur until January 1, 1975, or thereafter, a firm may use as the weighted average price at which natural gas liquid products were lawfully priced in first sale transactions on May 15, 1973, prices of not more than $.12 per gallon for propane, not more than $.12.5 per gallon for butane, and not more than $.13.5 per gallon for natural gasoline.

(d) Imputed May 15, 1973, first sale prices for natural gas liquids from new gas plants where groundbreaking did not occur until January 1, 1975, or thereafter. For purposes of determining lawful prices of natural gas liquids produced in a gas plant where groundbreaking did not occur until January 1, 1975, or thereafter, a firm may use as the weighted average price at which natural gas liquids were lawfully priced in first sale transactions on May 15, 1973, prices computed on the basis of not more than $.115 per gallon for propane content, not more than $.12 per gallon for butane content, and not more than $.13 per gallon for natural gasoline content.

(e) Imputed May 15, 1973, first sale prices for natural gas liquids and natural gas liquid products produced in gas plants where additional capital expenditures have been made on January 1, 1975, and thereafter. (1) For purposes of determining lawful prices of natural gas liquids and natural gas liquid products produced in a gas plant where additional capital expenditures have been made on or after January 1, 1975, resulting in an increase in either the

volumetric capacity of the plant or the extraction capability of the plant, a firm may use, in determining the weighted average price at which natural gas liquids and natural gas liquid products were lawfully priced on May 15, 1973, first sale prices which exceed the adjusted May 15, 1973, first sale prices otherwise permitted to be used under this section by not more than $.035 per gallon, provided that:

(i) The imputed May 15, 1973, first sale prices permitted under this section may exceed the adjusted May 15, 1973, per gallon prices otherwise permitted by an amount which is in the same proportion to $.035 as the increase in the book value of the plant attributable to the capital expenditures is to the total book value of the plant after the expenditures were made; and

(ii) The total amount of capital expenditures made must be equal to or greater than 50 percent of the original cost of the plant.

(2) For purposes of determining lawful prices of natural gas liquids and natural gas liquid products produced in a gas plant where additional capital expenditures have been made on or after January 1, 1975, resulting in the accommodation of a natural gas stream which could not otherwise have been processed in the plant, a firm may use, in determining the weighted average price at which natural gas liquids and natural gas liquid products were lawfully priced on May 15, 1973:

(i) Prices which are computed in accordance with the provisions of paragraph (d)(1) (i) and (ii) of this section; or

(ii) Natural gas liquid product prices of not more than $.12 per gallon for propane, not more than $.125 per gallon for butane, and not more than $.135 per gallon for natural gasoline, and natural gas liquid prices of not more than $.115 per gallon for the propane content, not more than $.12 per gallon for the butane content, and not more than $.13 per gallon for the natural gasoline content, provided that these imputed May 15, 1973, first sale prices may be used only with respect to production attributable to the newly accommodated natural gas stream.

[39 FR 44412, Dec. 24, 1974. Redesignated at 40 FR 6200, Feb. 10, 1975, and amended at 40 FR 39853, Aug. 29, 1975; 41 FR 24113, June 15, 1976]

§ 212.165 Increased processing costs.

(a) Rule. Subject to the limitations and requirements set forth in this section, a firm may increase the first sale price of natural gas liquids and natural gas liquid products which it sells to reflect, on a dollar-for-dollar basis, increased processing costs which it has incurred since the firm's base quarter. For purposes of this section, the base quarter for any firm is that fiscal quarter which includes the month of May 1973, except that if the firm commenced gas processing operations after May 1, 1973, the base quarter is the first full fiscal quarter of the firm after the commencement of gas plant production.

(b) Calculation of increased processing costs. (1) For any firm, processing costs with respect to any gas plant or plants for any current month are the total amount of allowable costs incurred (or deemed under this section to have been incurred) by that firm with respect to that gas plant or plants in that month, divided by the volume of natural gas liquids and natural gas liquid products owned by the firm (after processing) and produced in that plant or plants in that month. Processing costs with respect to such plant or plants for the base quarter are the total amount of allowable costs incurred, or deemed to have been incurred, by that firm with respect to such plant or plants in the base quarter, divided by the volume of natural gas liquids and natural gas liquid products owned by the firm and produced in that plant or plants in the base quarter. Provided, That in calculating such processing costs, the rules hereinafter set forth in this paragraph (b) and in paragraph (c) of this section shall be followed. Increased processing costs for any current month are the difference between processing costs for the current month and processing costs for the base quarter, multiplied by the volume of natural gas liquids and natural gas liquid products owned by the firm (after processing) and produced in the current month in the plant or plants for which processing costs are being measured. Total increased processing costs are the net of increases in particular items of allowable costs (including payments made or received under paragraph (c) (3) of this section), less decreases in other particular items of allowable costs (including payments made or received under paragraph (c) (3) of this section).

(2) Allowable costs. Allowable costs, for purposes of calculating processing costs and increased processing costs, are those costs defined below which are attributable to gas plant operations: Provided, That no costs shall be included in any particular category of processing costs if they are included in any other category of processing costs, or are included in product costs or marketing costs.

(i) Depreciation cost. Depreciation cost is the cost attributable to the depreciation of gas plant facilities and equipment used for processing natural gas or natural gas liquids. Depreciation costs for any gas plant facility or equipment shall be calculated, for both the base quarter and the current month, on a total-units-of-production basis, i.e., by amortizing the original cost of the particular investment

equally over the total volume of natural gas liquids and natural gas liquid products reasonably expected to be produced from the facility or equipment, regardless of the volumes actually produced or to be produced in the base quarter or in any current month. A firm claiming increased costs of depreciation shall establish and maintain records setting forth the data and analytical method by which base quarter and current month unit depreciation is calculated under these rules. A firm which purchases an existing facility shall use the same unit depreciation costs for that facility as the seller used, and shall obtain a certification from the seller as to such unit depreciation costs prior to attributing any depreciation to the facility purchased. In no event may a firm or firms claim, in cumulative increased depreciation costs for a particular capital asset, an aggregate amount of more than the total original dollar investment in that capital asset (counting any improvements as part of the original investment), nor shall any firm be permitted to claim increased depreciation costs to the extent that the cost of the asset is deemed under these rules to have been attributable to production of natural gas liquids or natural gas liquid products prior to October 1, 1978. If a firm calculates plant fuel costs under paragraph (b)(2)(iii)(B) of this section, no depreciation costs shall be allowed for capital investments which effect fuel conservation. At any gas plant where the firm uses an adjusted May 15, 1973, first sale price pursuant to § 212.164 (c), (d), or (e), depreciation shall not constitute an allowable processing cost. A firm may elect, on a plant-by-plant basis and at the time of first selling natural gas liquids or natural gas liquid products from that plant, to claim increased depreciation costs or to use the adjusted price under § 212.164 (c), (d), or (e) (where permitted). A firm shall be bound by its election in all subsequent months. A firm utilizing the adjusted prices of § 212.164 (c), (d), or (e) at any time prior to the effective date of this § 212.165(b)(2)(i) shall be deemed to have elected such method for the plant or plants in question in lieu of claiming increased costs of depreciation.

(ii) Labor cost. Labor cost is the total amount of direct and indirect remuneration or inducement for personal services which are reasonably subject to valuation for those personnel employed at a gas plant or directly involved in gas plant operations, including that portion of the costs of any contract with an unrelated entity attributable to personnel other than employees that perform such services. Costs in this category may include salaries paid to personnel who own all or any portion of, or receive profits from, the firm involved, for personal services that are wholly and specifically attributable to gas plant operations. Owner salary cost increases are limited to the weighted average percentage increase in salaries granted to all employees of the firm since May 15, 1973. Such salaries are not permitted as an allowable cost for any owner who did not draw a salary during May 1973 or the initial quarter of gas plant operations except where an owner has drawn a salary prior to May 1, 1979, but did not draw a salary during May 1973 or the initial quarter of the firm's operations because of economic or other financial considerations. In such a case a portion of the owner's current salary can be shown as an increased cost, up to the weighted average percentage increase in salaries granted to all other employees of the firm since May 15, 1973, or the initial quarter of the firm's operations. Salaries of owners must be reasonable and bear a direct relationship to services devoted to the firm's gas plant activities. The reallocation of "net profits" from operations to "owner salaries" for the sole purpose of increasing the costs available for passthrough will not be permitted. For purposes of this paragraph (b)(2)(ii), an "unrelated entity" is an entity which is not part of the firm and which has no equity interest in any gas plant or plants (or in the natural gas liquids or natural gas liquid products produced therefrom) in which the firm has such an interest.

(iii) Plant fuel cost—(A) In general. Plant fuel cost is the total amount of cost for fuels utilized to operate a gas plant. Except as provided in paragraph (b)(2)(iii)(B) of this section, if and to the extent that natural gas processed at the plant is used for plant fuel, no costs attributable thereto shall be accounted for as processing costs, but may be accounted for as cost of natural gas shrinkage under § 212.167.

(B) Optional plant fuel incentive. For any plant, a firm may calculate increased costs of plant fuel in the following manner: Provided, That the firm shall neither claim depreciation costs associated with capital investments which effect plant fuel conservation, nor use the cost of those investments to qualify for the incentive price of § 212.164 (c)-(e) if it calculates increased plant fuel costs in such fashion: Multiply the base gas plant fuel usage by the gas plant input for the current month and by the amount which represents the difference between average gas plant fuel cost rate in the current month and the average gas plant fuel cost rate in the base quarter where:

"Average gas plant fuel cost rate" means the weighted average cost of gas plant fuel per unit of energy utilized as fuel (e.g., dollars per million British Thermal Units (MMBtu) or dollars per thousand cubic feet (Mcf)). Where the plant fuel is natural gas processed at the plant, the total dollar amount of gas plant fuel for any period is determined by multiplying the volume of fuel by the sales price of the

residue gas in that period. Where residue gas has been sold on a different basis in the current month than in the base quarter (e.g., MMBtu versus Mcf), base quarter costs shall be converted into the unit under which residue gas is sold in the current month.

"Base gas plant fuel usage" means the amount of gas plant fuel, in units of energy (MMBtu or Mcf), used per Mcf or MMBtu of gas plant input during the base quarter.

"Gas plant input" means the volume of raw natural gas processed at the gas plant during the period in question.

(iv) Maintenance cost. Maintenance cost is the dollar amount of costs attributable to normal gas plant maintenance and repair, including the cost of contract maintenance under contract with an unrelated entity. For purposes of this paragraph (b)(2)(iv), the term "unrelated entity" has the meaning given that term in paragraph (b)(2)(ii), of this section.

(v) General and administrative costs. General and administrative costs are the ordinary and necessary expenses of management and administration (including overhead) attributable to gas plant operations under generally accepted accounting principles historically and consistently applied by the firm, provided that any such costs which are attributable to, or incurred by, a corporate or other organizational administrative unit not directly and exclusively involved with gas plant operations shall not be an allowable cost. Costs in this category include legal and accounting fees, interplant gas transportation cost, and salaries paid to personnel who own all or any portion of, or receive profits from, the firm involved, for personal services that are wholly and specifically attributable to gas plant operations. Owner salary cost increases are limited to the weighted average percentage increase in salaries granted to all employees of the firm since May 15, 1973. Owner salaries are not permitted as an allowable cost for any owner who did not draw a salary during May 1973 or the initial quarter of gas plant operations, except where an owner has drawn a salary prior to May 1, 1979, but did not draw a salary during May 1973 or the initial quarter of the firm's operations because of economic or other financial considerations. In such a case a portion of the owner's current salary can be shown as an increased cost, up to the weighted average percentage increase in salaries granted to all other employees of the firm since May 15, 1973, or the initial quarter of the firms operations. Salaries of owners must be reasonable and bear a direct relationship to services devoted to the firm's activities. The reallocation of "net profits" from operations to "owner salaries" for the sole purpose of increasing the costs available for passthrough is not permitted.

(vi) Federal, State, and local tax cost. Federal, State, and local tax cost is the cost of Federal, State, and local property, excise, franchise, and other similar taxes incurred with respect to gas plants or gas plant operations. However, the term does not include Federal, State, or local income taxes. The term also does not include production or severance taxes.

(vii) Utility cost. Utility cost is the dollar amount of costs incurred for utilities necessary for the operation of a gas plant.

(viii) Interest cost. Interest cost is the dollar amount incurred for interest on the amount of money borrowed from an unrelated entity for the purpose of constructing, expanding, or operating a gas plant, or which is otherwise attributable (based on relative operating costs or investment costs) to gas plant operations. For purposes of this paragraph (b)(2)(viii), the term "unrelated entity" has the meaning given that term in paragraph (b)(2)(ii) of this section.

(ix) Cost of operating materials and supplies. Operating materials and supplies cost is the cost of materials and supplies which are directly attributable to gas plant operations. This category includes materials such as absorption oil, process chemicals, and other industrial supplies which are not depreciable assets under generally accepted accounting practices historically and consistently applied by the firm.

(3) Limitations on increased processing costs for new plants. Notwithstanding any other provision of this § 212.165, if: (i) A firm had an interest in one or more gas plants (or in the production from one or more gas plants) which were operating in the base quarter, and if (ii) the firm separately calculates and aggregates increased processing costs for a gas plant or group of gas plants which were not in existence and operating in the base quarter, then, in calculating the increased processing costs for a new plant, the new plant's base quarter processing costs shall be equal to the firm's firmwide base period processing costs. If a particular volume of natural gas or natural gas liquids is currently being processed by another firm under a fee or cost-sharing arrangement, and such natural gas or natural gas liquids were being processed directly by the paying firm in the base quarter, base quarter processing costs for such natural gas or natural gas liquids shall include the costs of processing such natural gas or natural gas liquids.

(c) Accounting procedures for calculating processing costs incurred by a firm—(1) General. All processing costs shall be calculated in accordance with generally accepted accounting practices historically and consistently applied by the firm for certified annual financial statements filed by or on behalf of such firm with the Securities and Exchange Commis-

sion or a comparable State regulatory agency (or if no certified financial statements are so filed, according to generally accepted accounting practices historically and consistently applied by the firm for certified annual financial reports prepared by an independent accounting firm), except as otherwise provided in this section. No capital investments may be included in processing costs as expenses, but must be capitalized and depreciated as specified in the definition of depreciation costs.

(2) Extraordinary or irregular costs. Any item of cost which: (i) Is paid or incurred at greater than regular monthly intervals, or (ii) is paid or incurred each month but in significantly different amounts independent of variations in the amount of production shall be prorated or accrued over the appropriate period pursuant to generally accepted accounting practices historically and consistently applied for purposes of calculating processing costs under this section. In selecting the appropriate period for either the current month or the base quarter the burden shall be on the firm to choose that period which accurately reflects the period to which the particular item of cost is attributable. A firm shall maintain records setting forth the data and rationale under which the appropriate proration period is established, both for the base quarter and for any current month in which such extraordinary or irregular costs may be incurred. Costs in this category include, but are not limited to, annual taxes, insurance, and extraordinary maintenance expenses. However, if the total amount of all such irregular or extraordinary costs incurred in any current month is less than $0.0025 per gallon, such costs need not be prorated. Notwithstanding any other provisions of this paragraph (c)(2), costs which are not incurred at regular intervals, or which are incurred in amounts which vary substantially from period to period, may not be accrued, but must be prorated subsequent to their incurrence.

(3) Processing costs deemed incurred by a firm--(i) General rule. Except as otherwise provided in this paragraph (3), a firm's processing costs are only those costs attributable to gas plant operations, as defined in paragraph (b)(2) of this section, which the firm actually incurs. A firm shall deduct from its processing costs, pursuant to the following paragraphs (c)(3) (ii) and (iii) of this section, all or a portion of the amounts paid to it by other firms on account of the firm's processing (including gathering) of natural gas or natural gas liquids for such other firms. Paragraphs (3)(ii) and (iii) of this § 212.165(c)(3) apply to all firms that make or receive payments to or from another firm for the processing (including gathering) of natural gas or natural gas liquids, no matter how such payments are characterized. Firms that do not engage in any first sales (as defined in § 212.162) of natural gas liquids or natural gas liquid products are not required to account for processing fee or other payments made or received; however, if the other party or parties to such payments engage in any first sales of natural gas liquids or natural gas liquid products, such party or parties shall account for such payments as provided in this § 212.165(c)(3).

(ii) Apportionment of costs under gas plant operating agreements. Firms having an interest in the same gas plant (or in the production from the same gas plant) under a general gas plant operating agreement in which the parties agree to share the costs of operating the gas plant, either directly or by reimbursement to the actual gas plant operator, shall be deemed to have incurred allowable processing costs in accordance with the firms' applicable written agreement for the sharing of costs. In the absence a written cost sharing agreement, such firms shall be deemed to have incurred a portion of the total allowable processing costs at that gas plant determined as follows. The ratio of the firm's costs in the relevant period to total allowable costs of operating the gas plant in the same period shall be equal to the ratio of the volume of the natural gas liquids and natural gas liquid products produced at the plant and owned by the firm in the relevant period to the total volume of the production at the plant during the same period. Each firm shall be jointly and severally responsible for insuring that no more than the total amount of actual allowable costs (as defined in paragraph (b)(2) of this section) attributable to the natural gas liquids and natural gas liquid products produced in the plant or plants are allocated among all relevant firms. Payments which reflect a direct reimbursement of processing costs under a basic gas plant operating agreement shall not be treated under § 212.165 (c)(3)(iii) below, but shall be accounted for under this paragraph. Conversely, bona fide fee payments made or received in return for processing of natural gas or natural gas liquids shall not be treated under this subparagraph, but shall be accounted for under § 212.165(c) (3)(iii) below.

(iii) Payment and receipt of cash or in-kind consideration for processing natural gas or natural gas liquids. Where a firm makes or receives a bona fide payment, whether in cash or in the form of an in-kind transfer of natural gas liquids or natural gas liquid products, to or from another firm in return for the processing of natural gas liquids or natural gas liquid products, the firm shall calculate increased processing costs incurred by it as follows:

(A) The firm making such payments shall add to its otherwise allowable processing costs (as defined in paragraph (b)(2) of this section), in both the current month and the base quarter,

the amount of such payments made in the current month and the amount of such payments made in the base quarter, respectively. The firm shall then derive its increased processing costs as provided in paragraph (b)(1) of this section. Where increased processing costs are aggregated under paragraph (c)(4) of this section on a basis such that there are no base quarter costs attributable to the natural gas liquids or natural gas liquid products on account of which such payments are made, base quarter processing costs for such natural gas liquids or natural gas liquid products shall be calculated under paragraph (b)(3) of this section in the same manner as for new plants.

(B) The firm receiving such payments shall deduct from its otherwise allowable processing costs (as defined in paragraph (b)(2) of this section), in both the current month and the base quarter, the lesser of the amount of the payment received in the current month and the base quarter, respectively, or the amount of allowable processing costs attributable on a volumetric basis to the natural gas liquids or natural gas liquid products produced in the plant and owned by the paying firm after payment in the current month and the base quarter, respectively. The firm shall then derive its increased processing costs as provided in paragraph (b)(1) of this section. Where increased processing costs are aggregated under paragraph (c)(4) of this section on a basis such that there are no base quarter costs attributable to the natural gas liquids or natural gas liquid products on account of which such payments are made, base quarter processing costs for such natural gas liquids or natural gas liquid products shall be calculated under paragraph (b)(3) of this section in the same manner as for new plants. A firm shall value payments made in the form of in-kind transfers of natural gas liquids or natural gas liquid products under this paragraph (c)(3)(iii), by multiplying the number of gallons of the products paid or received by the firm's applicable base period price for the natural gas liquids or natural gas liquid products. To value base quarter transfers the firm shall use its actual May 15, 1973, selling price for the products transferred, and to value current period transfers the firm shall use the higher of its actual May 15, 1973, price of the applicable adjusted price of § 212.164. Once the transfers are valued a firm shall calculate its increased processing costs with respect to such in-kind payments in accordance with paragraphs (c)(3)(iii) (A) and (B) of this section.

(4) Aggregation and allocation of increased processing costs. The provisions of § 212.168 (a), (b), (c) and (e), which provide for the exclusion of increased product costs attributable to ethane, the aggregation of increased product costs, the allocation of increased product costs to propane, and the allocation of increased product costs among classes of purchaser, shall also apply to increased processing costs. Increased processing costs attributable to particular products shall be aggregated on the same basis and allocated to the same products as are increased product costs.

(d) Recovery of increased processing costs. Increased processing costs incurred by a firm shall be available for recovery in sales by that firm of natural gas liquids or natural gas liquid products in the current month, Provided, That such increased processing costs are allocated as provided in paragraph (c)(4) of this section. Subject to the provisions of § 212.169, those increased processing costs shall also be available for recovery in sales of natural gas liquids and natural gas liquid products in months following the current month, provided that such costs are allocated as provided in paragraph (c)(4) of this section.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[43 FR 43000, Sept. 21, 1978, as amended at 44 FR 77122, Dec. 28, 1979]

§ 212.166 Increased marketing costs.

(a) Rule. Subject to the limitations and requirements of this section, a firm may increase the first sale price of natural gas liquids and natural gas liquid products to reflect, on a dollar-for-dollar basis, increased marketing costs which it has incurred in the sale of such products since the base period.

(b) Calculation of increased marketing costs. (1) For any firm, marketing costs for any current month are the total amount of allowable costs incurred by that firm in that month with respect to sales of natural gas liquids and natural gas liquid products in that month, divided by the total volume of those products sold by that firm in that month. Base period marketing costs are the total amount of allowable costs incurred by the firm in the base period with respect to sales of natural gas liquids and natural gas liquid products in the base period, divided by the total volume of those products sold by the firm in the base period. In calculating current and base period marketing costs, a firm shall follow the rules hereinafter set forth in this paragraph (b) and

in paragraph (c) of this section. Increased marketing costs for any current month are the difference between marketing costs for the current month and marketing costs for the base period, multiplied by the volume of natural gas liquids and natural gas liquid products sold by the firm in the current month. For purposes of this section the base period is the 9-month period beginning January 1, 1973, and ending September 30, 1973, plus the result of adding the 3-month period beginning October 1, 1972, and ending December 31, 1972, and the 3-month period beginning October 1, 1973, and ending December 31, 1973, and dividing that sum by 2.

(2) Allowable costs. Allowable costs, for purposes of calculating marketing costs and increased marketing costs, are costs which fall within the following categories and which are attributable, under generally accepted accounting practices historically and consistently applied by the firm, to natural gas liquid and natural gas liquid products sales operations. No costs shall be included in any particular category of marketing costs if they are included in any other category of marketing costs, or are included in product costs of processing costs. Common costs attributable both to sales operations and to gas plant operations shall be attributed solely to gas plant operations and treated as processing costs.

(i) Labor cost. Labor cost is the total dollar amount of direct and indirect remuneration or inducement for personal services, which are reasonably subject to valuation, for those personnel employed by the firm and directly involved in the sales operations of natural gas liquids and natural gas liquid products. This category includes salaries which are paid to personnel who own all, or any portion of, or receive profits from, the firm involved, for personal services that are wholly and specifically attributable to the firm's activities. Owner salary cost increases are limited to the weighted average percentage increase in salaries granted to all other employees of the firm since May 15, 1973. Such salaries are not permitted as an allowable cost for any owner who did not draw a salary during May 1973 or the initial quarter of the firm's operations except where an owner has drawn a salary prior to May 1, 1979, but did not draw a salary during May 1973 or the initial quarter of the firm's operations because of economic or other financial considerations. In such a case a portion of the owner's current salary can be shown as an increased cost, up to the weighted average percentage increase in salaries granted to all other employees of the firm since May 15, 1973, or the initial quarter of the firm's operations. Salaries of owners must be reasonable and bear a direct relationship to services devoted to the firms's activities. The reallocation of "net profits" from operations to "owner salaries" for the sole purpose of increasing the costs available for passthrough is not permitted.

(ii) Utility cost. Utility cost is the dollar amount of costs incurred for utilities.

(iii) Interest cost. Interest cost is the dollar amount of costs incurred for interest on borrowing from an unrelated entity to the extent that such borrowing is for the purpose of financing any of the marketing costs set forth in paragraphs (b)(2) (i)-(vii) of this section (including costs of acquiring facilities on which depreciation is allowable under paragraph (b)(2)(vi) of this section).

(iv) Federal, State, and local tax cost. Federal, State, and local tax cost is the dollar amount of Federal, State, and local property, excise, franchise, and other similar taxes incurred which are associated with the sales operations of natural gas liquids and natural gas liquid products. Federal, State, and local income taxes are not includable in this amount.

(v) Maintenance cost. Maintenance cost is the dollar amount of operating cost attributable to maintenance operations which are associated with the sales operations of natural gas liquids and natural gas liquid products. Maintenance cost increase includes the cost of contract maintenance.

(vi) Depreciation cost. Depreciation cost is the cost attributable to the depreciation of equipment, machinery, and facilities which are associated with the sales operations of natural gas liquids and natural gas liquid products: Provided, That these costs are not otherwise covered by this section. If form 10-K is filed with the Securities and Exchange Commission, or an analogous report is filed with a State regulatory agency, the amount computed for depreciation cost increase shall be consistent with the figures used in preparing form 10-K or the analogous report. Accounting procedures used to compute depreciation cost increase by firms which do not file such form or report, or on whose behalf such form or report is not filed, shall be generally accepted accounting practices historically and consistently applied by the firm concerned for certified annual financial reports prepared by an independent accounting firm. No capital investments may be included in marketing costs as expenses, but all such investments must be capitalized and depreciated.

(vii) Overhead cost. Overhead cost is the dollar amount of costs of rent of real property, postage, office supplies, normal gas losses, insurance, employees' uniforms, outside legal and accounting fees, and transportation costs directly attributable to the sales operations of natural gas liquids and natural gas liquid products and not included in the calculation of increased product or processing costs. These costs shall be computed according to generally accepted accounting practices historically and consistently applied by the firm. Notwith-

standing anything in this paragraph (b)(2)(vii) to the contrary, if a firm aggregates and allocates marketing costs on the basis of separate inventories as provided under paragraph (b)(3) of this section, the costs of transporting natural gas liquids or natural gas liquid products from a gas plant to the first separate inventory point shall be considered a cost attributable to that inventory.

(3) Aggregation and allocation of increased marketing costs. A firm may aggregate and allocate increased marketing costs to its entire, undivided stock of natural gas liquids and natural gas liquid products, or to that portion of total stock which constitutes a separate inventory at the point in the firm's distribution system where the product first comes to rest beyond the gas plant, or to the separate products propane, butane, and natural gasoline, under generally accepted accounting practices historically and consistently applied by the firm. Where costs are attributable to more than one product and/or more than one inventory, a firm shall allocate them according to generally accepted accounting practices to all of the products and/or inventories to which they are attributable. The provisions of § 212.168 (c) and (d), which apply to the allocation of increased product costs to propane, shall also apply to increased marketing costs. Inventories not in existence in the base period shall have as their base period marketing costs the entire firm's base period marketing costs for that product.

(c) Recovery of increased marketing costs. A firm may recover increased marketing costs in sales of natural gas liquids and natural gas liquid products in the current month. Subject to the provisions of § 212.169, a firm may also recover these costs in months following the current month, provided that such costs are aggregated and allocated as provided in paragraph (b) (3) of this section.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[43 FR 43003, Sept. 21, 1978, as amended at 44 FR 77123, Dec. 28, 1979]

§ 212.167 Increased product costs.

(a) The first sale price of natural gas liquids or natural gas liquid products may be increased in each month as provided in § 212.167 to reflect, on a dollar-for-dollar basis, increased product costs since May 1973 attributable to the production of such natural gas liquids or natural gas liquid products.

(b) Increased product costs are (1) the difference between the weighted average cost per gallon of natural gas liquids purchased in the month of May 1973, and the weighted average cost per gallon of natural gas liquids purchased in the current month multiplied by the number of gallons of natural gas liquids purchased in the current month, (2) the difference between the weighted average cost per gallon of each natural gas liquid product purchased in the month of May 1973, and the weighted average cost per gallon of that natural gas liquid product purchased in the current month multiplied by the number of gallons of the natural gas liquid product purchased in the current month, plus (3) the difference between the weighted average cost of natural gas shrinkage per thousand cubic feet (MCF) of natural gas processed in the month of May 1973, and the weighted average cost of natural gas shrinkage per thousand cubic feet (MCF) of natural gas processed in the current month, multiplied by the number of thousand cubic feet (MCF's) of natural gas processed in the current month.

(c) Limitation on calculation of increased product costs attributable to purchases of natural gas liquids. In calculating the weighted average cost per gallon of natural gas liquids purchased in a first sale in the current month for the purpose of determining increased product costs under paragraph (b) of this section, a firm shall exclude those amounts attributable to the use by the seller of an adjusted May 15, 1973, selling price under § 212.164 in determining its lawful price to the purchaser.

(d) Exclusion of net-back payments from the calculation of increased product costs. In calculating the weighted average cost per gallon of purchased natural gas liquids for the purpose of determining increased product costs under paragraph (b) of this section, a firm shall exclude all amounts attributable to net-back sales.

(e) Separate aggregation and allocation of increased costs of certain imported natural gas liquids and certain imported propane, butane or natural gasoline. Anything in this subpart to the contrary notwithstanding, if purchased natural gas liquids, or purchased propane, butane or natural gasoline are or have been imported (or are exchanged for imports of such products) and for which separate inventory records are required to be maintained under § 211.88(c), increased costs of such purchased natural gas liquids or such purchased propane, butane or natural gasoline shall be separately calculated for each such separate inventory and shall be allocated to the natural gas liquids or the

propane, butane or natural gasoline in such inventory. Increased costs so calculated shall not be available for recovery in the prices of other natural gas liquids or other propane, butane or natural gasoline.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[39 FR 44412, Dec. 24, 1974, Redesignated and amended at 40 FR 6200, Feb. 10, 1975; 40 FR 39854, Aug. 29, 1975. Further redesignated at 43 FR 43003, Sept. 21, 1978; 44 FR 60655, Oct. 19, 1979]

§ 212.168 Allocation of increase product costs.

(a) Exclusion of increased product costs attributable to ethane. The total amount of increased product costs attributable each month to a given volume of natural gas shall be reduced each month by an amount equal to the product of the increased product costs multiplied by

$$(V_e^u/V^u)$$

where:

V^u=The total volume of all natural gas liquid products and ethane derived from that volume of natural gas and sold in the current month, and

V_e^u=The total volume of all ethane derived from that volume of natural gas and sold in the current month.

(b) Aggregation of increased product costs. Where increased product costs measured with respect to particular volumes of natural gas or natural gas liquids processed in one or more gas plants in a month are different, (1) the increased product costs measured with respect to a particular volume of natural gas may be allocated to the particular sales volumes of natural gas liquid products produced therefrom; or, in the alternative, (2) the total amount of increased product costs measured with respect to the total amount of natural gas and natural gas liquids processed in one or more gas plants under common ownership in a month may be allocated to the total sales volume of natural gas liquid products produced therefrom, provided that once an election in accordance with this paragraph has been made, the elected method of allocating product costs shall continue to be used in the months subsequent to the election.

(c) Increased product costs allocable to propane. The total amount of increased product costs allocable to the price of propane derived from a particular volume of natural gas for each twelve month period of August 1 through July 31, shall not exceed the amount of increased product costs determined pursuant to paragraphs (a) and (b) of this section to be attributable to that volume of natural gas and allocable to the sales volume of natural gas liquid products derived therefrom multiplied by

$$(V_p/V_n)$$

where:

V_n=The total volume of all natural gas liquid products derived from that volume of natural gas and sold during the current period Aug. 1 through July 31, and

V_p=The total volume of propane derived from that volume of natural gas and sold during the current period Aug. 1 through July 31.

(d) Increased costs of purchased natural gas liquids and natural gas liquid products. The total amount of increased product costs allocable to all sales of propane shall not exceed the sum of the amount of increased product costs determined pursuant to § 212.166(b)(2) to be attributable to purchases of propane, plus the amount of increased product costs determined pursuant to paragraphs (a), (b), and (c) of this section to be allocable to the price of propane derived from a particular volume of natural gas.

(e) Allocation of increased product costs among classes of purchaser. In computing maximum lawful prices for sales of natural gas liquid products other than propane, the amount of increased product cost allocable to such products pursuant to this section shall be equally applied to each class of purchaser. The total amount of increased product costs allocable to natural gas liquid products may be apportioned among natural gas liquid products, other than propane, in whatever amounts are deemed appropriate. In computing maximum lawful prices for sales of propane, unequal amounts of increased product costs may be applied to different classes of purchaser, provided, That the highest amount of increased product cost applied to the weighted average May 15, 1973, selling price to any class of purchaser shall not exceed by more than 100 percent the amount of increased product cost applied to the weighted average May 15, 1973,

selling price to any other class of purchaser, and, provided further, That no greater amount of increased product cost can be applied to the weighted average May 15, 1973, selling price of propane in sales to any class of purchaser which includes an independent marketer, as defined in § 211.51 of this Chapter, or a purchaser that uses the product for residential use, as defined in § 211.51 of this Chapter, than is applied to the weighted average May 15, 1973, selling price of propane to any other class of purchaser.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[39 FR 44412, Dec. 24, 1974. Redesignated at 40 FR 6200, Feb. 10, 1975, and amended at 40 FR 39854, Aug. 29, 1975; 41 FR 24113, June 15, 1976. Further redesignated and amended at 43 FR 43003, Sept. 21, 1978]

§ 212.169 Carry-forward of increased costs; corrections for overrecovery of increased costs.

(a) Carry forward of increased costs. Subject to the requirements and limitations contained in this section, a firm may include in the prices of natural gas liquids and natural gas liquid products the increased product, processing, and marketing costs which it has not previously recovered. Increased processing and marketing costs incurred prior to October 1, 1978, shall not however be permitted to be recovered under this section. Increased costs which a firm has not previously recovered shall retain the aggregated or segregated character that they had as current increased costs under the applicable provisions of this subpart, and shall be allocated only to products distributed from the same center of aggregation. However, a firm that maintains separate inventories for calculating increased marketing costs, and distributes products from a gas plant to a particular first inventory shall allocate to that inventory an amount of increased product and processing costs equal to the greater of: (1) An amount determined by multiplying current increased unit product and processing costs by the number of units distributed from the gas plant, or (2) the unit amount recovered in sales from that gas plant to nonaffiliated purchasers multiplied by the number of units distributed from the gas plant.

(b) Corrections for overrecovery of increased costs. If in any month a firm charges prices for natural gas liquids or natural gas liquid products that result in the recovery of an amount greater than the increased costs which it is allowed under this subpart, the firm shall subtract the excess amount recovered from its May 15, 1973, selling prices for the product, cost centers and class of purchaser with respect to which such overrecoveries occurred, not later than the third month after the month in which it recovers the excess amount. A firm shall not deem any increased costs to have been overallocated to propane except on an annual basis, as provided in § 212.168(c), § 212.165(c)(4), and § 212.166 (b)(3).

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[43 FR 43004, Sept. 21, 1978]

§ 212.170 Increased product costs for natural gas liquids and natural gas liquid products derived from a new gas stream.

For purposes of determining increased product costs attributable to natural gas liquids and natural gas liquid products produced from a new gas stream where no sale of the residue gas was made on May 15, 1973, a firm shall use as its May 15, 1973, price for the residue gas, the lower of: 23 cents per thousand cubic feet (MCF) or 23 cents per million British thermal units (MMBTU) of residue natural gas, whichever is consistent with the sales terms of the contract under which the residue gas is currently sold; or the actual price at which the residue gas was sold on the first day following May 15, 1973, on which a sale was made.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-

385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[41 FR 24113, June 15, 1976. Redesignated at 43 FR 43003, Sept. 21, 1978]

§ 212.171 Net-back calculations.

For purposes of calculating net-back revenues, revenues from sales of natural gas liquid products shall exclude any amounts that represent recoupment of increased cost of crude oil, provided for pursuant to Subpart E.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974; Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 9570; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[39 FR 44412, Dec. 24, 1974. Redesignated at 40 FR 6200, Feb. 10, 1975, and further redesignated at 43 FR 43003, Sept. 21, 1978]

§ 212.172 Records required to be maintained.

Prices otherwise permitted to be charged pursuant to this subpart to reflect increased product costs, increased processing costs, and increased marketing costs shall not be charged unless records adequate to demonstrate such increased product costs, increased processing costs, and increased marketing costs are maintained. The ERA will treat gas plant operators as responsible in the first instance for maintaining such records, without, however, relieving gas plant owners and other entities subject to these regulations of the responsibility for compliance with these regulations. Where one or more gas plants are under common ownership, the records required by this section may be kept in the aggegate for all of the gas plants concerned.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub. L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974; Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[43 FR 43004, Sept. 21, 1978]

§ 212.173 Certification requirements.

(a) Certification to purchasers of natural gas liquids. Each seller of natural gas liquids shall certify to each purchaser in a first sale transaction the per gallon increment included in the price charged to that purchaser which results from the use by the seller of an adjusted May 15, 1973, selling price under § 212.164, in determining the lawful price to that purchaser.

(Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, as amended, Pub.L. 93-511, Pub. L. 94-99, Pub. L. 94-133, Pub. L. 94-163, and Pub. L. 94-385; Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, Pub. L. 94-332, Pub. L. 94-385, Pub. L. 95-70, Pub. L. 95-91; Energy Policy and Conservation Act, Pub. L. 94-163, as amended, Pub. L. 94-385, Pub. L. 95-70; Energy Conservation and Production Act, Pub. L. 94-385, as amended, Pub. L. 95-70, Pub. L. 95-91; Department of Energy Organization Act, Pub. L. 95-91; E.O. 11790, 39 FR 23185; E.O. 12009, 42 FR 46267)

[43 FR 43004, Sept. 21, 1978]

Subpart L--Resales of Crude Oil

(This subpart is omitted)

Appendix A to Part 212 -- Standby Regulations

(This Appendix is omitted)

Appendix B to Part 212 -- Special Rule No. 2

(This Appendix is omitted)

[illegible]

[illegible]

[illegible]

Subpart [illegible]—[illegible] of Crude Oil

[illegible]

[illegible]

1001, Pub. L. 96-294, 94 Stat. 611; [illegible] Production Act, [illegible]

[illegible]

§ 212.171 [illegible]

[illegible]

[44 FR [illegible], [illegible]]

§ 212.172 [illegible]

[illegible]

[illegible]

B. 10 CFR 375, Mineral Leasing: General, 45 FR 9530, 9538, February 12, 1980.

SUBCHAPTER C--LEASING

PART 375--MINERAL LEASING: GENERAL

Subpart A--General Provisions

AUTHORITY: Pub. L. 89-554, 80 Stat. 383 (5 U.S.C. 553); secs. 302,303, and 644, Pub. L. 95-91, 91 Stat. 578-579, 579-580, 599 (42 U.S.C. 7152, 7153 and 7254); E.O. 12009, 42 FR 46267.

Subpart A--General Provisions

§ 375.001 Purpose and scope.

(a) The purpose of this Part 375 is to describe DOE's general authority in the mineral leasing area and to establish general provisions applicable to DOE's mineral leasing regulations in this Subchapter C.

(b) The mineral leasing regulations issued by DOE pursuant to sections 302(b) and 303 of the DOE Act will be found in this Subchapter C.

(c) Section 303(a) of the DOE Act provides that the Secretary of the Interior retains any mineral leasing authorities not transferred under section 302(b) of the DOE Act and that he is solely responsible for the issuance and supervision of Federal leases and the enforcement of all regulations applicable to the leasing of mineral resources, including but not limited to regulations applicable to lease terms and conditions and production rates.

§ 375.002 Applicability.

The provisions in Subpart A and Subpart B of this Part 375 are applicable to all of the regulations in Subchapter C, unless otherwise noted.

§ 375.003 Authority.

(a) Section 302(b) of the DOE Act transferred to, and vested in, the Secretary of Energy the functions of the Secretary of the Interior to promulgate regulations under the Outer Continental Shelf Lands Act, the Mineral Lands Leasing Act, the Mineral Leasing Act for Acquired Lands, the Geothermal Steam Act of 1970, and the Energy Policy and Conservation Act, which relate to: the fostering of competition for Federal leases (including, but no limited to, prohibition on bidding for development rights by certain types of joint ventures); implementation of alternative bidding systems authorized for the award of Federal Leases; the establishment of diligence requirements for operations conducted on Federal leases (including, but not limited to, procedures relating to the granting or ordering by the Secretary of the Interior of suspension of operations or production as they relate to such requirements); setting rates of production for Federal leases; and the specifying of the procedures, terms and conditions for the acquisition and disposition of Federal royalty interest taken in kind.

(b) The function of the Secretary of the Interior to establish production rates for all Federal leases was also transferred to, and vested in, the Secretary of Energy by section 302(c) of the DOE Act.

(c) Section 303(c)(1) of the DOE Act requires the Secretary of the Interior to afford the Secretary of Energy not less than thirty days, prior to the date on which DOI first publishes or otherwise prescribes the terms and conditions on which a Federal lease will be issued, to disapprove any term or condition of such lease that relates to any matter with respect to which the Secretary of Energy has authority to promulgate regulations under section 302(b) of the DOE Act. No such term or condition may be included in such a lease if it is disapproved by the Secretary of Energy.

(d) In exercising his authority to promulgate regulations under section 302(b) of the DOE Act, the Secretary of Energy is required by section 303(b) of the DOE Act to consult with the Secretary of the Interior during the preparation of such regulations and to afford the Secretary of the Interior not less than thirty days prior to the date on which the DOE first publishes or otherwise prescribes regulations to comment on the content and effect of such regulations.

§ 375.004 Definitions.

For purposes of this Subchapter C:

"Area" or "region" means the geographic area or region over which the USGS designated official has jurisdiction, unless the context in which those words are used indicates a different meaning is intended.

"Designated Official" means a representative of DOI subject to the direction and supervisory authority of the Director, the Chief, Conservation Division, USGS, and the appropriate Regional Conservation Manager, Conservation Division, USGS, authorized and empowered to supervise and direct all oil and gas operations

and to perform other duties prescribed in 30 CFR Part 250 (offshore).

"Director" means Director, United States Geological Survey, Department of the Interior.

"DOE" means the Department of Energy, including the Secretary of Energy, or his or her delegate. "DOE Act" means the Department of Energy Organization Act (Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. 7101 et seq.)).

"DOI" means the Department of the Interior, including the Secretary of the Interior, or his or her delegate.

"Federal lease" means an agreement which, for any consideration, including, but not limited to, bonuses, rents or royalties conferred, and convenants to be observed, authorizes a person to explore for, or develop, or produce (or to do any or all of these) oil and gas, coal, oil shale, tar sands, and geothermal resources on lands or interests in lands under Federal jurisdiction.

"Gas" means natural gas as defined by the Federal Energy Regulatory Commission.

"OCS" means the Outer Continental Shelf, which includes all submerged lands (1) that lie seaward outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (Pub. L. 31-35, 67 Stat. 29, (43 U.S.C. 1301)) and (2) of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

"OCSLA" means the Outer Continental Shelf Lands Act, as amended (Act of August 7, 1953, Ch. 345, 67 Stat. 462, 43 U.S.C. 1331 et seq., as amended by Pub. L. 95-372, 92 Stat. 629).

"Oil" means a mixture of hydrocarbons that exists in a liquid or gaseous phase in an underground reservoir and which remains or becomes liquid at atmospheric pressure after passing through surface separating facilities, including condensate recovered by means other than a manufacturing process.

"USGS" means the United States Geological Survey, Department of the Interior.

[45 FR 9538, Feb. 12, 1980]

§ 375.005 Effect on existing regulations.

In some instances regulations issued by DOE in this Subchapter C may supersede, in whole or in part, certain regulations which have been promulgated by DOI. The specific regulations superseded will be identified in the applicable rulemakings issued for codification in this Subchapter C.

Subpart B--Administrative Procedures

§ 375.101 Interpretation.

Any person seeking an interpretation of the mineral leasing regulations in this Subchapter C shall file a written request with the General Counsel of DOE. Each such request shall be processed in accordance with the procedures established in Subpart F of 10 CFR Part 205.

Prior to issuing an interpretation of these regulations, the General Counsel shall afford the Solicitor of DOI not less than thirty days to comment on the content and effect of such interpretation.

§ 375.102 Rulemaking.

Any person seeking issuance, amendment, or repeal of the mineral leasing regulations in this Subchapter C shall file a formal written request with the General Counsel of DOE. The request shall be filed as a petition for rulemaking and treated in accordance with the procedures, as applicable, of Subpart L of 10 CFR Part 205.

C. 10 CFR 376, Bidding Systems for Outer Continental Shelf Oil and Gas Leasing, 45 FR 9539, February 12, 1980, amended by: 45 FR 36800, May 30, 1980; and 45 FR 62031, September 18, 1980.

1. Preamble, 10 CFR 376, Bidding Systems for Outer Continental Shelf Leasing, 45 FR 9536, February 12, 1980.

DEPARTMENT OF ENERGY

10 CFR Parts 375 and 376

Bidding Systems for Outer Continental Shelf Oil and Gas Leasing

AGENCY: Department of Energy.

ACTION: Final rule.

SUMMARY: These regulations establish three bidding systems for utilization in Outer Continental Shelf (OCS) oil and gas lease sales. These bidding systems are: (1) cash bonus bid with a fixed royalty; (2) royalty bid with a fixed cash bonus; and (3) cash bonus bid with a sliding scale royalty. Each of these systems includes a fixed rental component. These bidding systems are three of those specifically authorized by section 205 of the Outer Continental Shelf Lands Act Amendments of 1978. The intended effect of these bidding systems is to enhance competition for oil and gas leases on the OCS, provide a fair return to the Federal Government for its resources, and develop new oil and gas resources in an efficient and timely manner. This rule is being issued under the authority of sections 302(b) and 303(c) of the Department of Energy Organization Act and section 8 of the Outer Continental Shelf Lands Act, as amended.

EFFECTIVE DATE: This regulation will be effective March 13, 1980.

FOR FURTHER INFORMATION CONTACT:

Susan Pearce, Leasing Policy Development Office, U.S. Department of Energy, 12th & Pennsylvania Avenue, N.W., Room 2313, Washington, D.C. 20461, (202) 633-9035.

Michael T. Skinker, Office of General Counsel, U.S. Department of Energy, 1000 Independence Avenue, S.W., Room 5E-074, Washington, D.C. 20585, (202) 252-2900.

Frederic C. Appel (Public Affairs), Resource Applications, U.S. Department of Energy, 12th & Pennsylvania Avenue, N.W., Room 3307, Washington, D.C. 20461, (202) 633-9418.

SUPPLEMENTARY INFORMATION:

I. INTRODUCTION

Section 302(b) of the Department of Energy Organization Act (DOE Act, Pub. L. 95-91, 91 Stat. 578-579 (42 U.S.C. 7152(b))), transferred to the Secretary of Energy certain authorities previously held by the Secretary of the Interior under the Outer Continental Shelf Lands Act (OCSLA), the Mineral Lands Leasing Act, the Mineral Leasing Act for Acquired Lands, the Geothermal Stream Act of 1970, and the Energy Policy and Conservation Act. As a result, with respect to Federal leases, the Secretary of Energy is authorized to promulgate regulations that (1) foster competition, (2) implement alternative bidding systems, (3) establish diligence requirements, (4) set rates of production, and (5) specify the procedures, terms and conditions for the acquisition and disposition of Federal royalty interests taken in kind. In addition, under section 302(c) of the DOE Act (42 U.S.C. § 7152(c)), the Secretary of Energy is granted the authority to establish rates of production for Federal leases and under section 303(c)(1) (42 U.S.C. 7153(c)(1)), the Secretary reviews and may approve or disapprove any term or condition of a Federal lease that relates to DOE's section 302(b) DOE Act authority to promulgate regulations.

On July 26, 1979, the Department of Energy (DOE) issued proposed regulations to establish and describe three bidding systems authorized for Outer Continental Shelf (OCS) lease sales by section 8 of the OCSLA (Act of August 7, 1953, 67 Stat. 468 (43 U.S.C. 1337), as amended by section 205 of the Outer Continental Shelf Lands Act Amendments of 1978 (OCSLAA, Pub. L. 95-372, 92 Stat. 640-646)), and invited comments from the public (44 FR 46235, August 6, 1979).

Written comments were received from nine oil companies and the Department of the Interior (DOI). Pursuant to section 5 of the OCSLA, this regulation was submitted to the Department of Justice (DOJ) for review with respect to matters which may affect competition. DOJ did not submit views on this regulation.

DOE has considered all the comments submitted during the public comment period in preparing these final regulations. The major issues raised by the comments are addressed below. Certain of the comments, however, involved matters outside the scope of these regulations,

while others addressed matters that are within the scope of DOI's responsibilities. These are not addressed. In addition, editorial changes and corrections have been made throughout the final rule as necessary.

II. MAJOR COMMENTS

The principal purpose of these regulations is to establish and describe the bidding systems that are to be used in OCS lease sales pursuant to DOE's authority in sections 302(b) and 303(c) of the DOE Act. These regulations establish three of the bidding systems authorized by the OCSLAA (cash bonus bid with a fixed royalty, royalty bid with a fixed cash bonus and cash bonus bid with a sliding scale royalty). They are applicable only to sales of oil and gas leases on the OCS.

On November 30, 1979, DOE also proposed to establish a "fixed net profit share" bidding system for use in OCS lease sales (44 FR 70389, December 6, 1979). Public comments on this proposal will be accepted until March 7, 1980, and public hearings are to be held in Washington on February 20, in Houston on February 26, and in San Francisco on February 28.

The system or systems to be utliized in each OCS lease sale will be chosen from the bidding systems that are established by these regulations, by the final net profit share regulations, and by future OCS bidding system regulations. Bidders will submit bids and pay for leases on the basis of the bidding system that is applicable to a particular tract, as specified in the notice of lease sale. In the cash bonus bid system (§ 376.110(a)(1)), persons competing for a Federal tract will submit bids in the form of cash bonuses. Under the royalty bid system (§ 376.110(a)(2)), persons competing for a Federal tract will submit bids in the form of royalty rates, to be paid in money or in kind, based on a percentage of production saved, removed, or sold. In the cash bonus bid with a sliding scale royalty system (§ 376.110(a)(3)), as in the cash bonus bid with a fixed royalty system, persons competing for Federal leases will submit bids in the form of cash bonuses. However, in the sliding scale system, a sliding scale formula or schedule will be utilized to adjust the royalty rate according to the amount or value of production saved, removed or sold during a specified production period.

A. ALTERNATIVE BIDDING SYSTEMS

In general, most of the industry comments were critical of the use of the royalty bid with a fixed cash bonus system, while the reaction was mixed as to use of a cash bonus bid with a sliding scale royalty system. Clearly, industry perferred exclusive use of the traditional cash bonus bid with a fixed royalty system for the sale of lease tracts on the OCS. For the reasons listed below, DOE does not believe that this represents an accepted option.

In enacting the OCSLAA, Congress demonstrated its commitment to the use of alternative bidding systems by explicitly authorizing the use of seven systems and permitting the development of others. Congress authorized that new bidding arrangements be developed and used on an experimental basis in order to strike a proper balance between securing a fair market return to the Federal Government for the lease of its lands, increasing competition for the use of its resources, and providing the incentive of a fair profit to the oil companies which must risk their investment capital. Further, Congress ensured the use of alternative systems by directing that bidding systems other than the cash bonus bid with a fixed royalty system be applied to not less than 20 percent and not more than 60 percent of the total area offered for leasing each year during the period September 18, 1979, to September 18, 1984.

The three bidding systems whose use is authorized by the regulation issued today have all been used in previous lease sales. The regulation authorizes but does not require the use of the different systems in any particular lease sale. As recognized by Congress, competing interests may be served by the use of different systems under different sets of circumstances. Prior to the application of any bidding system to tracts offered in an OCS lease sale, both DOI and DOE would review carefully its ability to achieve specified objectives in that sale. By selecting carefully from available bidding systems, DOE believes it is possible to maximize the net benefits deriving from OCS lease sales.

B. ROYALTY RATE ISSUES

One comment recommended deletion of the language in § 376.110(a)(3)(i)(A) that allows the use of a step function (i.e., schedule) to establish the royalty rate to be applied to specified ranges of value of production. This recommendation was made because the company believed that specified royalty ranges would tend to encourage manipulation of production rates to keep royalty rates within a lower range. Although in all applications of the cash bonus bid with a sliding scale royalty system to date the Federal Government has only utilized a continuous function to establish the royalty rate, the suggested deletion was not made because DOE wants to retain the flexibility to experiment with this option in appropriate circumstances.

One comment objected to the method proposed in § 376.110(a)(3)(i)(C) for royalty payment calculations stating that royalties should be based on actual value rather than on an adjusted value and that the proposed method may be detrimental to the interests of both the

government and the lessee. This comment further suggested that the method of calculation currently used in the OCS lease form be utilized. It should be noted that only the royalty rate is calculated based on the adjusted value of production and that the royalty payment itself is calculated by applying the royalty rate to the actual value of production. DOE has decided to retain the royalty payment calculation method set forth in the proposed rule because it believes that this method fairly balances the interests of the lessee and the Federal Government.

One comment suggested that § 376.110(a)(3)(i)(C)(4) be clarified to avoid problems that could be created by revisions in published values of GNP indexes. This suggestion was adopted and the section was revised to require that the inflation factor utilized be based on the GNP fixed weighted price index that is first published in the Survey of Current Business by the Bureau of Economic Analysis, U.S. Department of Commerce, for a calendar period corresponding to a production period.

Recommendations were made by DOI and one other person to revise § 376.110(a) to allow for the reduction of the royalty rate below 12 1/2 percent in order to encourage increased production on the lease area. DOE has adopted this suggestion and revised the regulations pursuant to the authority of section 205(a)(3) of the OCSLAA to allow for a reduction in the royalty rate after lease issuance.

C. APPLICATION AND DESIGN OF BIDDING SYSTEMS

Three persons suggested that different bidding systems should not be used for tracts on a single geologic structure because this could create differences in investment strategies and incentives, cause additional administrative and cost sharing problems (especially if unitization were to occur), and prevent an accurate and definitive analysis of the items listed in § 376.111(b)(1). One comment urged DOE to place a restriction in the regulations prohibiting the use of different bidding systems on the same structure.

While it is not DOE's policy to recommend the application of different bidding systems to tracts on the same geologic structure, in practice this may be difficult to avoid because sometimes it is impossible to identify tracts common to a single OCS structure prior to a lease sale. If DOE were to place an absolute prohibition in the regulations, the Federal Government could be placed in a position of unknowingly violating its own regulation, thus, potentially subjecting itself to litigation. Successful legal challenge to a lease sale's validity could nullify the extensive preparatory efforts for the sale, as well as any exploratory and developmental efforts undertaken by the lessee on the tract in question. DOE believes that in those few cases where different systems may be used for tracts on the same structure, unit or cost sharing agreements can be devised to reduce or eliminate any administrative or cost sharing problems that may occur. Further, DOE believes it is necessary to retain the flexibility to vary bidding systems utilized for tracts on a common structure.

One comment urged DOE to include a requirement in the regulations for a full hearing with due notice to all interested parties prior to the application in a particular OCS lease sale of any bidding system that had not been used in previous lease sales. In establishing bidding systems for use in OCS lease sales, DOE provides an opportunity both for the submission of written comments and for a public hearing. In the establishment of new or particularly complex systems, such as the fixed net profit share system, DOE has provided a comment period longer than that required by applicable law. This provides ample notice and opportunity for public participation in the implementation of alternative bidding systems. Therefore, the suggested change would be duplicative of the rulemaking process and could cause delays in leasing OCS oil and gas. Interested parties should avail themselves of the opportunity to comment on new bidding systems during the public comment period provided for in the rulemaking process.

DOI wanted the proposed rules to be changed on the grounds that they failed to treat rental and royalty payments according to usage in the OCSLAA and by industry and government. DOI thought that it was unnecessary to include rental as a bidding system element, as it was a lease term and condition, and disapproved of the term "fixed annual rental" because it was misleading.

It is DOE's view that these regulations conform to the OCSLAA and prior industry and government usage. Rental has been included as part of the bidding systems because its magnitude directly impacts the magnitude of the cash bonus and the royalty provisions. Therefore, DOE has not made the suggested change regarding rental provisions. However, in order to avoid confusion, all references in the body of the regulations to the term "fixed annual rental" have been changed to read "annual rental."

One comment stated that § 376.111(b)(1)(v) should include "and estimated time required to bring the lease into production" as one of the key economic factors to be considered in determining the choice of a bidding system. Although DOE presently considers the estimated time required to bring a lease into production in its analysis of bidding systems to be utilized at a lease sale, DOE does not feel that it is appropriate to include this as a factor in § 376.111(b)(1)(v), because selection of a bidding system is not dependent upon this factor, whereas selection is dependent upon the factors

currently listed in § 376.111(b)(1)(v).

D. DEFINITIONS

Several comments were received on the wording of the proposed definitions. DOE has reviewed all such comments and modified the definitions as discussed below.

The definitions of "maximum royalty rate" and "minimum royalty rate" were revised to make them clearer and consistent with related DOI regulations.

Two persons objected to the definition of "OCS lease sale" in § 376.102 and offered suggested wording for a revised definition. One commenter wanted the definition to reflect the fact that issuance of a lease occurs subsequent to and separate from a lease sale. DOI wanted the definition to note that OCS leases are offered for sale by competitive sealed bidding and that leases are issued to the highest responsible qualified bidder upon determination by the Secretary of the Interior that the high bid reflects the fair market value of a tract.

DOE has revised the definition of "OCS lease sale" to mean "the DOI proceeding by which leases for certain OCS tracts are offered for sale by competitive bidding and during which bids are received, announced and recorded." DOE believes that this definition most accurately reflects what occurs at an OCS lease sale. The requirement for sealed bidding has not been adopted because DOE does not want to preclude the possibility of using oral bidding at future lease sales. The suggested wording "leases are issued to the highest responsible qualified bidder upon determination by the Secretary of the Interior that the high bid reflects the fair market value for a tract" was not adopted because this is merely a restatement of existing requirements in DOI regulations and because lease issuance is subsequent to and separate from a lease sale.

Comments were also offered on the definition of "person" proposed at § 375.004. The commenters thought that the proposed definition was expanded beyond the scope of the OCSLAA, was inappropriate in light of other proposed DOE regulations and existing DOI regulations, and was unnecessarily inclusive. One of the commenters recommended using the definition of "person" in section 301 of the OCSLAA.

In response to these comments, DOE has decided to utilize the definition of "person" given in section 2(d) of the OCSLA. It is DOE's interpretation that this is the definition of "person" that Congress intended for application to bidder qualification determinations. The definition of "person" at section 301 of the OCSLAA has application only to Title III of the Act. The definition of "person" has been moved to § 376.002 to reflect the fact that it is to have application only to the OCS oil and gas leasing provisions of DOE's regulations.

DOI and one other person commented on the definition of "qualified bidder." In response to these comments, this definition has been revised to reflect all the present DOI bidder qualification requirements. In addition, a separate definition of "highest responsible qualified bidder" has been added to the regulations in order to maintain compatibility with the OCSLAA and with existing and proposed DOI regulations.

Two commenters recommended that the definition of "tract" be revised to make it clearer, more complete, and consistent with related regulations. DOE has revised the definition based upon suggested wording.

E. ROYALTY PRICING ISSUE

DOI stated its belief that DOE's regulations should provide that the DOI royalty be based on the increased price that an operator receives when he obtains an exception to the DOE Mandatory Petroleum Price Regulations (10 CFR Part 212). DOE agrees with this comment and has dealt with this question in another rulemaking. In the "Final Rulemaking Regarding Disposition of Federal Outer Continental Shelf Royalty Oil" issued recently, DOE amended the DOE Mandatory Petroleum Price Regulations (10 CFR 212.74(e)) to extend price relief to royalty interest owners, including the United States, in cases where exception relief has been granted to those with an operating interest. Pursuant to that amendment, the percentages of crude oil sold at lower tier, upper tier, or other prices may be the same for all owners of an interest in a property for which DOE has issued, to one or more of the owners thereof, an exception order under Subpart D of 10 CFR Part 205 specifying the percentages to be sold at each price.

F. GENERAL

The suggestion was made to delete from the first sentence of § 376.111(a) language restricting the applicability of the subparagraph to the three bidding systems established by this regulation in order to provide for application of subparagraph (a) to any bidding system that may be established by future regulations. Since it is DOE's intent to promulgate other regulations establishing additional bidding systems, this suggested deletion was made.

A recommendation was made to modify the requirement in § 376.111(b)(2) that computers be used in bidding system analyses, so as to allow their discretionary use. Since DOE did not intend to require the use of computer simulation models when it proposed these regulations, a revision was made to allow the discretionary use of such models.

DOI recommended that the language of the final

rules match the language of the DOI regulations on OCS leasing at 43 CFR 3300. To the extent possible, DOE has endeavored to conform the wording of these regulations to that of the current DOI regulations.

Pursuant to the requirements of the National Environmental Policy Act of 1969 (NEPA, Pub. L. 91-190, 83 Stat. 852 (42 U.S.C. 4321 et. seq.)), DOE has reviewed this regulation and has determined that it clearly does not constitute a "major Federal action significantly affecting the quality of the human environment" within this meaning of NEPA. Accordingly, no environmental impact statement is required to support this action.

Because DOE determined that this was a significant regulation having a major impact within the meaning of the DOE procedures to implement Executive Order 12044 on "Improving Government Regulations (DOE Order 2030.1, 44 FR 1032, January 3, 1979), a regulatory analysis was prepared for these regulations. This analysis may be obtained from DOE's Freedom of Information Office.

[Outer Continental Shelf Lands Act, ch. 345, 67 Stat. 462 (43 U.S.C. 1331 et seq., 1953), as amended by Pub. L. 95-372, 91 Stat. 340; Department of Energy Organization Act, Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. 7101 et seq., 1977); E.O. 12009, 42 FR 46267]

In consideration of the foregoing, Chapter II, Title 10 of the Code of Federal Regulations, is amended as set forth below.

RUTH M. DAVIS,
Assistant Secretary, Resource Applications

FEBRUARY 5, 1980

2. Preamble, 10 CFR 376, Outer Continental Shelf Oil and Gas Joint Bidding, 45 FR 62029, September 18, 1980.

DEPARTMENT OF ENERGY

Office of Leasing Policy Development

10 CFR Part 376

Leasing; Final Rulemaking Regarding Outer Continental Shelf Oil and Gas Joint Bidding Regulations

AGENCY: Department of Energy.

ACTION: Final rule.

SUMMARY: This regulation revises the joint bidding requirements of the Department of the Interior for Outer Continental Shelf (OCS) oil and gas leases. The regulation requires submission of Statements of Production of crude oil, natural gas equivalents, and liquefied petroleum products only by those persons chargeable with an average daily production in excess of 1.6 million barrels during a 6-month production period. Any such persons are then prohibited in the following 6-month bidding period from submitting bids jointly with any other person similarly chargeable. This regulation is being issued pursuant to the Department of Energy's rulemaking responsibilities under section 302 (b)(1) of the Department of Energy Organization Act to foster competition for Federal OCS oil and gas leases.

EFFECTIVE DATE: This rule is effective September 10, 1980.

FOR FURTHER INFORMATION CONTACT:

Robert C. Gillette, (Office of Public Hearings Management), Economic Regulatory Administration, 2000 "M" Street, N.W., Washington, D.C. 20461, (202) 254-5201.

Edward F. Mulholland, (Leasing Policy Development), U.S. Department of Energy, 1200 Pennsylvania Avenue, N.W., Room 2313, Washington, D.C. 20461, (202) 633-8136.

Michael T. Skinker, (Office of General Counsel), U.S. Department of Energy, 1000 Independence Avenue, S.W., Room 5E-064, Forrestal Building, Washington, D.C. 20585, (202) 252-2900.

Fred Appel, Public Affairs, Resource Applications, U.S. Department of Energy, 1200 Pennsylvania Avenue, N.W., Room 3307, Washington, D.C. 20461, (202) 633-9418.

SUPPLEMENTARY INFORMATION: Sections 302 and 303 of the Department of Energy Organization Act, (DOE Act, Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. 7101 et seq.)) transferred from the Department of the Interior (DOI) to the Department of Energy (DOE) certain authorities previously held by the Secretary of the Interior under the Outer Continental Shelf Lands Act (OCSLA, Act of August 7, 1953, 67 Stat. 462 (43 U.S.C. 1331)), as amended by the Outer Continental Shelf Lands Act Amendments of 1978 (OCSLAA, Pub. L. 95-372, 92 Stat. 629), the Mineral Lands Leasing Act, the Mineral Leasing Act for Acquired Lands, the Geothermal Steam Act of 1970, and the Energy Policy and Conservation Act. As a result, with respect to Federal leases, the Secretary of Energy is authorized to promulgate regulations to:

(1) Foster competition,
(2) Implement alternative bidding systems,
(3) Establish diligence requirements,
(4) Set rates of production, and
(5) Specify the procedures, terms and conditions for the acquisition and disposition of Federal royalty interests taken in kind. In addition, under section 302(c) of the DOE Act, the Secretary of Energy is vested with the authority to establish rates of production for Federal leases, and under section 303(c) the Secretary reviews and may disapprove any term or condition of a Federal lease that relates to DOE's authority under section 302(b) to promulgate regulations. Under his authority to promulgate regulations to foster competition, the Secretary may issue regulations that prohibit bidding for leases by certain types of joint ventures.

This regulation is being issued pursuant to DOE's authority under section 302(b)(1) of the DOE Act to regulate joint bidding in order to foster competition for Federal Outer Continental Shelf (OCS) oil and gas leases. As required under section 303(b) of the DOE Act, the Secretary of the Interior was consulted during preparation of this proposed regulation, and DOI's substantive comments have been incorporated into this proposed regulation. As required by section 5 of the OCSLA (section 204 of the OCSLAA), DOE has transmitted a copy of the proposed regulation to the Attorney General for his views on any matters contained herein that may affect competition. No comments have been received from the Department of Justice.

BACKGROUND

On May 20, 1980, DOE issued a proposed regulation regarding OCS oil and gas joint bidding regulations (45 FR 35830, May 28, 1980), and invited public comment over a two-month period ending July 25, 1980. No public hearing was held in view of DOE's belief that the proposed regulation would have no adverse impacts, that it posed no substantial issue of law or fact,

and that it would be unlikely to have a substantial impact on the national economy or large numbers of individuals or businesses. No request to hold a public hearing has been received.

COMMENTS

In response to publication of the proposed regulation, DOE received eleven comments, from companies active in various aspects of the oil and gas industry, from the Georgia Department of Natural Resources, from the Council on Wage and Price Stability and from DOI. The comments enthusiastically and unanimously supported the content and objective of the proposed regulation. Several comments provided suggestions for further revisions of the joint bidding requirements. All the comments were helpful and received careful consideration.

In general, the comments provided thorough confirmation of DOE's belief that the present joint bidding requirements constitute a barrier to entry and competition in OCS lease sales, for at least some firms. Crown Central Petroleum Corporation, for example, commented that the proposed regulation "will certainly enhance the ability of smaller firms to participate in joint ventures." Pogo Producing Company, itself a small firm active on the OCS, endorsed the proposed regulation, while considering it likely that regulatory requirements such as that eliminated by this regulation have precluded some firms from bidding. And the comments of the New York Gas Group (NYGAS) agreed explicitly with DOE that the joint bidding filing requirement may constitute a barrier to participation in OCS lease sales, as well as that the final regulation "should encourage broader participation in OCS lease sales and increased competition for OCS leases."

Major firms and governmental agencies also lent strong support for the proposed regulations. Chevron, Exxon, Gulf, and Shell all concurred in the proposal without reservation. Among government agencies, the Georgia Department of Natural Resources supported the proposed regulation. DOI similarly endorsed the proposal. COWPS "enthusiastically" supported the revision in joint bidding requirements, as a step toward promoting competition.

Chevron recommended that DOE further amend the joint bidding requirements, to define a subsidiary as a company, more than 50 percent of whose voting stock is indirectly or directly owned by another company; this definition would replace the current language of "50 percent or more" in 43 CFR 3316.3-3(a)(3). DOE intends to examine this suggestion in connection with a general review of joint bidding procedures, and accordingly, does not adopt it at this time.

Other comments, from Gulf and Exxon, suggested deletion of the joint bidding filing requirement for all bidders, except those whose status with regard to the threshold of 1.6 million barrels of average daily production has changed. DOE recognizes that, as a general proposition, the number and identity of companies restricted from bidding together jointly has remained stable. Nonetheless, DOE has not adopted this suggestion, because semiannual certification of chargeable production does not impose an unreasonable burden on major firms.

NYGAS suggested incorporation into the regulation of language from the preamble, that this regulation is intended to "supersede only those requirements of 43 CFR 3316.3 that are inconsistent" with it, in order to avoid confusion until DOI conforms its joint bidding regulations to conform to the final regulation. DOE has declined to adopt this suggestion, as DOI is concurrently amending its joint bidding regulations.

THE FINAL REGULATION

In view of the comments, the final regulation is identical to the proposal. This regulation revises DOI's regulatory scheme for OCS joint bidding (43 CFR 3316.3, 44 FR 38280 (June 29, 1979)), which currently requires each party intending to bid jointly at any OCS lease sale to have previously submitted a Statement of Production, covering crude oil, natural gas equivalents, and liquefied petroleum products, for the 6-month production period preceding the 6-month bidding period in which the OCS sale is held. The party submitting the Statement of Production affirms whether it is chargeable with an average daily production in excess of 1.6 million barrels worldwide during the applicable 6-month production period. Each party filing a Statement of Production under the present regulations is chargeable with its own production, that of subsidiaries and parents, as well as its proportionate share of production by any person in which the filing party holds an ownership or control interest, or which holds such an interest in the filing party, to the extent that any such interest amounts to at least 5 percent ownership or control.

The sole purpose of the requirement to file a Statement of Production is to identify those firms that, by virtue of the amount of daily production which they control, are precluded from bidding together in OCS lease sales. Parties chargeable with an average daily production in excess of 1.6 million barrels are placed on a current "List of Restricted Joint Bidders," and may not bid jointly with any other party on this List. They may, however, bid jointly with parties which have submitted Statements of Production but are not chargeable with more than 1.6 million barrels of average daily production. In the more than four years since DOI promulgated its joint bidding regulations, the same nine or ten

companies, out of the hundreds of firms filing Statements of Production, have been consistently placed on the semiannual "List of Restricted Joint Bidders."

Smaller companies are frequently able to participate in OCS lease sales only through formation of joint ventures. Since current DOI regulations prevent any party from bidding jointly for OCS leases without first having filed a Statement of Production, smaller firms, as well as major firms, must prepare a document in order to bid jointly for OCS leases. The joint bidding regulations were originally intended to increase participation in OCS lease sales through selective prohibition in joint ventures by major firms. However, since the current regulations require all parties to file Statements of Production in order to bid jointly, the burdensome nature of this requirement on some smaller firms may have impeded or even precluded some smaller firms from participation in OCS lease sales, contrary to the original intent of the joint bidding regulations to foster competition among bidders. This position received strong confirmation in the comments, and was strenuously supported by both government and industry.

While numerous extension of filing deadlines have mitigated the more serious impacts of this regulation, such as withdrawal or exclusion of a participant, revision of this filing requirement seems a more sensible approach. The requirement for submission of Statements of Production has placed a disproportionate burden on smaller companies, and on DOI, by generating superfluous paperwork as well as necessitating numerous extensions of filing periods to accommodate smaller bidders unfamiliar with OCS regulations.

Therefore, the final regulation is intended to enhance the competitive nature of the joint bidding process for OCS oil and gas leases by limiting this filing requirement to those companies subject to the prohibition on joint bidding (i.e., placed on the List of Restricted Joint Bidders). Removal of the requirement for all others is intended to encourage their participation in OCS lease sales. DOE's intent was thoroughly borne out in the comments. After examination of the current joint bidding regulations (43 CFR 3316.3), pursuant to DOE's regulatory authority to foster competition under section 302(b) of the DOE Act, DOE has decided to defer consideration of more extensive revision to the joint bidding procedures pending further analysis. DOE is reviewing the current procedures to determine whether need for such revision exists. The regulation has been drawn narrowly in order to change the current regulatory filing practice only to the extent necessary to achieve the above stated purpose. The terms employed in this proposed rule are defined exactly as in DOI's current joint bidding regulations.

DOE intends this regulation to supersede only those requirements of 43 CFR 3316.3 that are inconsistent with it, and notes that DOI is concurrently amending its joint bidding regulations to conform to this regulation.

SIGNIFICANCE REVIEW

DOE has determined that this proposed regulation is significant, but will not have a major impact within the meaning of DOE's procedures to implement Executive Order 12044 on "Improving Government Regulations" (DOE Order 2030, 44 FR 1032, January 3, 1979. Therefore, a regulatory analysis is not required for this proposed regulation.

ENVIRONMENTAL ANALYSIS

After reviewing the proposed regulation pursuant to DOE's responsibilities under the National Environmental Policy Act of 1969 (Pub. L. 91-190, 83 Stat. 852 (42 U.S.C. 4321 et seq.)), DOE has determined that the proposed action does not constitute a major Federal action significantly affecting the quality of the human environment. Therefore, DOE has determined that no environmental assessment or environmental impact statement is required for the proposed regulations.

(Outer Continental Shelf Lands Act, Act of August 7, 1953, ch. 345, 67 Stat. 462 (43 U.S.C. 1331 et seq.), as amended by Pub. L. 95-372, 92 Stat. 629; Department of Energy Organization Act, Pub. L. 95-91, (91 Stat. 565 (42 U.S.C. 7101 et seq.); E.O. 12009, 42 FR 46267.))

In consideration of the foregoing, it is proposed to amend Chapter II, Title 10 of the Code of Federal Regulations as set forth below.

DANIEL M. OGDEN, JR.,
Acting Assistant Secretary, Resource Applications

SEPTEMBER 10, 1980

3. Regulations, 10 CFR 376, Bidding Systems for Outer Continental Shelf Oil and Gas Leasing, 45 FR 9539, February 12, 1980, amended by: 45 FR 36800, May 30, 1980; and 45 FR 62031, September 18, 1980.

PART 376--OUTER CONTINENTAL SHELF OIL AND GAS LEASING

Subpart A--General Provisions

AUTHORITY: Act of August 7, 1953, ch. 345, secs. 2 and 8, 67 Stat. 468 (43 U.S.C. 1331 and 1337), as amended by sec. 205, Pub. L. 95-372, 92 Stat. 462 and 629; secs. 302, 303 and 644, Pub. L. 95-91, 91 Stat. 578-579, 579-580, 599 (42 U.S.C. 7152, 7153 and 7254); E.O. 12009, 42 FR 46267.

Subpart A--General Provisions

§ 376.001 Purpose and scope.

The purpose of this Part 376 is to implement sections 302(b) and 303 of the DOE Act by providing regulations which relate to the fostering of competition including, but not limited to, regulations to prohibit joint bidding for development rights by certain types of joint ventures; the implementation of alternative bidding systems; and the establishment of diligence requirements for Federal OCS leases issued under the OCSLA.

§ 376.002 Definitions.

For purposes of this Part 376:

"OCSLA" means the Outer Continental Shelf Lands Act (Act of August 7, 1953, ch. 345, 67 Stat. 462 (43 U.S.C. 1331 et seq.), as amended by Pub. L. 95-372, 92 Stat. 629).

"OCS lease" means a Federal lease for oil and gas issued under the OCSLA.

"Person" includes, in addition to a natural person, an association, a State, or a private, public, or municipal corporation.

Subpart B--Bidding Systems

§ 376.101 Purpose and scope.

(a) This subpart establishes the several bidding systems that may be utilized in connection with the offering and sale of Federal leases for the exploration, development and production of oil and gas resources located on the OCS.

(b) Only bidding systems established by this subpart shall be utilized in OCS lease sales.

§ 376.102 Definitions.

For purposes of this Subpart B--

"Highest responsible qualified bidder" means a person who has met the appropriate requirements of 43 CFR 3316 and has submitted a bid higher than any other bids by qualified bidders on the same tract.

"Highest royalty rate" means the highest per centum rate payable to the United States, as specified in the lease, in amount or value of the production saved, removed or sold.

"Lowest royalty rate" means the lowest per centum rate payable to the United States, as specified in the lease, in amount or value of the production saved, removed or sold.

"OCS lease sale" means the DOI proceeding by which leases for certain OCS tracts are offered for sale by competitive bidding and during which bids are received, announced and recorded.

"Production period" means the period during which the amount of oil and gas produced from a tract, or, if the tract is unitized, the amount of oil and gas as allocated under a unitization formula, will be measured for purposes of determining the amount of royalty payable to the United States.

"Qualified bidder" means a person, who has met the appropriate requirements of 43 CFR 3316.

"Tract" means a designation assigned solely for administrative purposes to a block or combination of blocks that are identified by a leasing map or an official protraction diagram prepared by DOI.

"Value of production" means the value of all oil and gas production saved, removed or sold from a tract, or, if the tract is unitized, the value of all oil and gas production saved, removed or sold and credited to the tract under a unitization formula, during a production period, which value is determined in accordance with § 376.110(b).

§ 376.110 Bidding systems.

(a) A single bidding system selected from those listed in this paragraph shall be applied to each tract included in an OCS lease sale.

(1) Cash bonus bid with a fixed royalty rate of not less than 12-1/2 per centum in amount or value of the production saved, removed or sold

and an annual rental.

(i) The royalty rate to be paid by the highest responsible qualified bidder shall be a percentage of the amount or value of the production saved, removed or sold. Such royalty rate shall not be less than 12-1/2 per centum at the beginning of the lease period in amount or value of production and shall be specified in the notice of OCS lease sale published in the Federal Register.

(ii) The amount of cash bonus to be paid is determined by the qualified bidder submitting the bid. Any deferment and the schedule of payments shall be included in the notice of OCS lease sale published in the Federal Register.

(iii) The annual rental to be paid by the highest responsible qualified bidder shall be the amount specified in the notice of OCS lease sale published in the Federal Register.

(2) Royalty rate bid based on per centum in amount or value of the production saved, removed, or sold, with a fixed cash bonus and an annual rental.

(i) The royalty rate to be paid is determined by the qualified bidder submitting the bid and shall be based on a percentage of the amount or value of the production saved, removed, or sold.

(ii) The cash bonus to be paid by the highest responsible qualified bidder shall be an amount specified in the notice of OCS lease sale published in the Federal Register.

(iii) The annual rental to be paid by the highest responsible qualified bidder shall be the amount specified in the notice of OCS lease sale published in the Federal Register.

(3) Cash bonus bid with diminishing or sliding royalty rate of not less than 12-1/2 per centum at the beginning of the lease period in amount or value of the production saved, removed, or sold, and annual rental.

(i)(A) The royaly rate to be paid by the highest responsible qualified bidder shall be a percentage of the amount or value of the production saved, removed or sold. The royalty rate shall be calculated by utilizing either a sliding scale formula, which relates the royalty rate established thereby to the adjusted value of the oil and gas produced during the production period, or a schedule that establishes the royalty rate that will be applied to specified ranges of adjusted value of production. The description of the sliding scale formula or schedule shall include the relationship between adjusted value of production and royalty rate, and a stipulation of the lowest royalty rate and highest royalty rate. The sliding scale formula or schedule shall be included in the lease issued to the person who is the successful bidder as one of the lease terms and conditions.

(B) The royalty rate shall not be less than 12-1/2 per centum at the beginning of the lease period in amount or value of the production saved, removed or sold and shall be specified in the notice of OCS lease sale published in the Federal Register.

(C) Royalty payment calculation.

(1) The royalty rate utilized in the calculation of royalty payments is based on an adjusted value of production, and is established through application of a sliding scale formula or a schedule to the adjusted value of production.

(2) The adjusted value of production shall be determined by applying an inflation factor to the actual value of production.

(3) The established royalty rate is applied to the actual value of production, which results in the determination of amount in dollars to be paid to the United States by the person awarded the lease or the amount of royalty oil and gas to be taken in kind by the United States.

(4) The production period for purposes of determining value of production shall be stated in the notice of OCS lease sale that is published in the Federal Register. The inflation factor utilized shall be based on the gross national product fixed weighted price index that is first published in the Survey of Current Business by the Bureau of Economic Analysis, U.S. Department of Commerce, for a calendar period corresponding to a production period. The procedures for making the inflation adjustment shall be stated in the notice of OCS lease sale published in the Federal Register.

(ii) The amount of cash bonus to be paid is determined by the qualified bidder submitting the bid. Any deferment and the schedule of payments shall be included in the notice of OCS lease sale published in the Federal Register.

(iii) The annual rental to be paid by the highest responsible qualified bidder shall be the amount specified in the notice of OCS lease sale published in the Federal Register.

(4) Cash bonus bid with a fixed share of the net profits of no less than 30 per centum to be derived from the production of oil and gas from the lease area and a fixed annual rental--(i) Net profit share payment calculation. The amount of the net profit share payment to the United States by the person awarded the lease shall be determined for each month by multiplying the net profit share base times the net profit share rate, in accordance with § 390.022.

(A) Net profit share base. (1) The net profit share base shall be calculated in accordance with § 390.021.

(2) The capital recovery factor needed to calculate the allowance for capital recovery, in accordance with § 390.020, shall be specified in the notice of OCS lease sale published in the Federal Register and may vary from tract to tract.

(B) Net Profit share rate. The net profit share rate, which determines the fixed share of the net profits owed to the United States, shall be a percentage that is specified in the notice

of OCS lease sale published in the Federal Register. Such net profit share rate shall not be less than 30 percent of the net profit share base and may vary from tract to tract.

(ii) The amount of cash bonus to be paid is determined by the person submitting the bid. Any deferment and the schedule of payments shall be included in the notice of OCS lease sale published in the Federal Register.

(iii) The annual rental to be paid by the person awarded the lease shall be the amount specified in the notice of OCS lease sale published in the Federal Register.

(b) The value basis for determining the actual value of production and for purposes of computing royalty in accordance with the bidding systems established by paragraph (a) of this section shall be as described in 30 CFR 250.64; Provided, however, that with respect to oil, the first sale of which is controlled under 10 CFR Part 212, the value shall not exceed the lawful first sale price of such oil; and provided further, that with respect to gas, the value shall not exceed the sale price established by the Federal Energy Regulatory Commission.

(c) DOE may, by rule, add to or modify the bidding systems listed in paragraph (a) of this section, in accordance with the procedural requirements of section 501 of the DOE Act.

[45 FR 36800, May 30, 1980]

§ 376.111 Criteria for selection of bidding systems and bidding system components.

(a) In analyzing and making recommendations to DOI regarding the application of one of the bidding systems listed in § 376.110(a) to tracts selected for any OCS lease sale, and in reviewing lease terms and conditions prior to determining whether to exercise its section 303(c)(1) DOE Act disapproval authority, DOE may, in its discretion, consider the following purposes and policies, recognizing that each of the purposes and policies may not be specifically applicable to the selection process for a particular bidding system and tract or may present a conflict that will have to be resolved in the process of bidding system selection, and that the order of listing does not denote a ranking:

(1) Providing fair return to the Federal Government;

(2) Increasing competition;

(3) Assuring competent and safe operations;

(4) Avoiding undue speculation;

(5) Avoiding unnecessary delays in exploration, development, and production;

(6) Discovering and recovering oil and gas;

(7) Developing new oil and gas resources in an efficient and timely manner;

(8) Limiting administrative burdens on Government and industry; and

(9) Providing an opportunity to experiment with various bidding systems to enable the identification of those that are the most appropriate for the satisfaction of the objectives of the United States in OCS lease sales.

(b)(1) In considering the potential disapproval of the application of the bidding system or systems for an OCS lease sale and the components of such system or systems, and in performing the analysis and review referred to in § 376.111(a), DOE may, in its discretion, take into account the following in relation to their impact upon the purposes and policies enumerated in paragraph (a) of this section:

(i) A projection of the number and characteristics of persons who would be interested in and capable of participating in the sale;

(ii) The relationship between economic rent and government revenue;

(iii) The incentives and disincentives for exploration, development and production;

(iv) The projected level of total production and expected production profile;

(v) The estimated size and location of potential reservoirs, including the type of resources (oil and/or gas), depth of water, climatic region, proximity to pipelines, proximity to leased and/or developed tracts and leasing history;

(vi) Location of potential reservoirs that overlap boundaries and unitization considerations;

(vii) Risk sharing between lessor and lessee; and

(viii) Administrative burden on the lessor and lessee.

(2) Some of the above factors are tract-specific, whereas others have a regional orientation. In making the evaluation associated with application of the above factors to the process of applying bidding systems to the tracts included in an OCS lease sale, objective and subjective analytical techniques will be employed, which may include the application of computer simulation models.

(c) The bidding systems listed in §§ 376.110 (a)(2) and (3) shall be applied to not less than 20 per centum and not more than 60 per centum of the total area offered for leasing each year during the five-year period commencing on September 18, 1978, unless DOI determines, after consultation with DOE, that the maximum and minimum per centum limitations set forth in this section are inconsistent with the purposes and policies of the OCSLA.

Subpart D--Joint Bidding

§ 376.301 Purpose.

The purpose of the regulations in this Subpart D is to encourage participation in OCS oil and gas lease sales by limiting the requirement for filing Statements of Production to certain joint bidders.

§ 376.302 Definitions.

For purposes of this Subpart D, all the terms used shall be defined as in 43 CFR 3316.3.

§ 376.303 Joint bidding requirements.

(a) Any person who submits a joint bid for any OCS oil and gas lease during a six-month bidding period and who was chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products, shall have filed a Statement of Production with the Director, Bureau of Land Management, in accordance with the requirements of 43 CFR 3316.3. The Statement of Production shall state that the person filing the Statement is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products.

(b) No person chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products may submit a joint bid for any OCS oil and gas lease during the applicable six-month bidding period with any other person similarly chargeable. Such bids shall be disqualified and rejected.

(c) No person may submit any bid during the applicable six-month bidding period pursuant to any agreement, the terms of which would result in two or more persons, each chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products, acquiring or holding any interest in the tract for which the bid is submitted. Such bid shall be disqualified and rejected.

[45 FR 62031, Sept. 18, 1980]

D. 10 CFR 390, Accounting Procedures for Net Profit Share Payments, 45 FR 36800, May 30, 1980.

1. Preamble, 10 CFR 390, Net Profit Share Payments, 45 FR 36784, May 30, 1980.

DEPARTMENT OF ENERGY

10 CFR Parts 376, 390

Final Rulemaking Regarding a Fixed Net Profit Share Bidding System for Outer Continental Shelf Oil and Gas Leases and Accounting Procedures for Determining Net Profit Share Payments

AGENCY: Department of Energy.

ACTION: Final rule.

SUMMARY: These regulations establish a "fixed net profit share" bidding system for use in lease sales of Outer Continental Shelf oil and gas tracts. The bidding system uses cash bonus as the bid variable and requires net profit share payments at a rate that is constant for the duration of the lease and a fixed annual rental payment. These regulations also establish accounting procedures that oil and gas firms are required to use in order to calculate net profit share payments due the United States for the right to produce oil and gas from Outer Continental Shelf leases issued under net profit share bidding systems. The most significant changes from the proposed regulation include a modification of the definition of the capital recovery period and changes to the accounting procedures, most notably those dealing with required inventories, audits, and records retention. This regulation implements rulemaking responsibilities under section 8(a) of the Outer Continental Shelf Lands Act, as amended by Pub. L. 95-372, that were transferred to the Department of Energy under sections 302(b) and 303(c) of the Department of Energy Organization Act.

EFFECTIVE DATES: The amendment to Part 376 contained in this regulation and Part 390 shall be effective May 14, 1980.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

I. Introduction

Sections 302 and 303 of the Department of Energy Organization Act (DOE Act, Pub. L. 95-91, 91 Stat. 578-580 (42 U.S.C. 7152, 7153)) transferred to the Secretary of Energy certain authorities previously held by the Secretary of the Interior under the Outer Continental Shelf Lands Act (OCSLA), the Mineral Lands Leasing Act, the Mineral Leasing Act for Acquired Lands, the Geothermal Steam Act of 1970, and the Energy Policy and Conservation Act. Specifically, with respect to Federal leases issued under these statutes, section 302(b) of the DOE Act authorizes the Secretary of Energy to promulgate regulations which relate to the: (1) Fostering of competition for Federal leases (including, but not limited to, prohibition on bidding for development rights by certain types of joint ventures); (2) implementation of alternative bidding systems authorized for the award of Federal leases; (3) establishment of diligence requirements for operations conducted on Federal leases (including, but not limited to, procedures relating to the granting or ordering by the Secretary of the Interior of suspension of operations or production as they relate to

such requirements); (4) setting rates of production for Federal leases; and (5) specifying the procedures, terms, and conditions for the acquisition and disposition of Federal royalty interests taken in kind.

The Secretary of Energy is specifically authorized to promulgate regulations under the OCSLA as they relate to the implementation of alternative bidding systems authorized for the award of Federal Outer Continental Shelf (OCS) leases (section 202(b)(2) of the DOE Act) and to disapprove any term or condition of a Federal OCS lease which relates to the authority to promulgate regulations under section 302(b)(§ 303(c)(1) of the DOE Act).

On November 30, 1979, the Department of Energy (DOE) issued a proposed regulation (44 FR 70390, December 6, 1979) to establish a fixed net profit share bidding system for use in OCS lease sales. The proposed bidding system differed in significant respects from the traditional bidding system used for OCS lease sales under which leases were issued on the basis of a cash bonus bid with subsequent payments to the government based on a fixed royalty and a fixed annual rental. The proposed bidding system retained cash bonus as the bid variable, but replaced the royalty paymemt as the basis on which the Federal Government would receive further payments for its resources with payment of a fixed share of the net profits. The regulation as proposed also established accounting procedures for allocating expenditures incurred by lessees during exploration, development and production of net profit share leases and for calculating net profit share payments. To the extent feasible, DOE based the accounting procedures in the proposed regulation on those generally used within industry. In addition, the proposed regulation established procedures for auditing by the Federal Government of lessees' accounting practices and net profit share calculations and prescribed the process whereby a lessee might challenge any adjustment to its calculations resulting from such auditing. The proposal incorporated a fixed capital recovery system as the means through which lessees would recover costs of exploration and development from production revenues, as well as a reasonable return on investment.

Implementation of a fixed net profit share bidding system satisfies a primary intention of Congress in enacting the OCSLA Amendments of 1978 (Amendments Pub. L.-95-372, 92 Stat. 629) that there be experimentation with various bidding systems. Explicit in the Amendments is Congress' conclusion that terms and conditions under which leases are awarded, i.e., the bidding and leasing process, have an important effect on orderly and efficient resource development. In particular, "with the present shortage of investment capital that will prevail for many years, increasing risk of uncertainty, and the increasing integration and concentration of energy industries, there is some doubt whether cash bonus bidding remains the best system for the future." (Report of the House Ad Hoc Select Committee on the Outer Continental Shelf. H.R. Rep. No. 95-590 to accompany H.R. 1614, 95th Congress, 1st Session (1977), p. 54). Thus, Congress directed through the Amendments that bidding arrangements other than the cash bonus-fixed royalty system be developed and used on an experimental basis, so as to "strike a proper balance between securing a fair market return to the Federal Government for the lease of its lands, increasing competition in exploitation of resources, and providing the incentive of a fair profit to the oil companies, which must risk their investment capital" (House Report, p. 54).

A review of the Amendment's legislative history indicates that Congress was particularly interested in profit share bidding systems. Congress's perception was that large cash bonus payments may inhibit competition for OCS leases by preventing smaller independent firms from participating in OCS development.

By design, use of a net profit share system places greater emphasis on contingency payments for generating fair returns to the government, and thereby less reliance on the initial cash bonus. Reduction of cash bonus bids constitute a primary effect intended under the proposal. The proposal was also intended to result in increased production of oil and gas from the OCS, foster development of marginal oil and gas fields, increase effective competition for OCS leases, and free more funds for exploration in addition to increasing total revenue to the public.

DOE has determined that initial experimentation with a net profit share bidding system should retain cash bonus as the bid variable. This determination is based upon the belief that profit share rate bidding will exhibit the same problems experienced with royalty rate bidding, i.e., a tendency to overbid the profit share rate, speculative bidding, and inefficient resource development.

Since the administration of this regulation is the responsibility of the U.S. Geological Survey (USGS) within the Department of the Interior (DOI), utilization of this bidding system will result in greater administrative responsibilities for the USGS, relating to determination of proper rates for certain costs, concern for inventory, and performance of periodic audits. USGS regulations are not superseded by this action but must be followed in conjunction with this regulation, as appropriate.

Pursuant to § 204 of the Amendments, a copy of the proposed regulation was transmitted to the Attorney General for his views on any matters contained herein that may affect competition. No comments have been received. DOE consulted with DOI in the preparation of this regulation and its views have been carefully

considered in the development of the final regulation.

II. Analysis of Public Comments

A. General

The proposed regulation was published in the Federal Register on December 6, 1979 (44 FR 70390) and public comment was invited over a period of three months; the comment period closed on March 7, 1980. During the comment period, DOE held public hearings on the proposed regulation in Washington, D.C. and Houston, Texas. In response to the proposal, comments were received from 27 private firms (all actively engaged in the offshore oil and gas industry), 2 State agencies, and 2 Federal agencies.

The comments divided logically along several lines. Most of the comments received from industry, for example, expressed some degree of opposition to the concept of a net profit share system. For a variety of reasons, however, the degree of opposition ranged from strong objection to mild disapproval of the concept. Some disagreed with the underlying retionales of the regulation, asserting that sufficient competition already exists for OCS leases or that the persent cash bonus--fixed royalty bidding system has served optimally to facilitate recovery of oil and gas from the OCS. Others felt that the proposed regulation would fail to achieve its goals, except for increasing revenue to the public. Few comments wholeheartedly endorsed the proposal.

A second area of concern focused on the proper structure of a net profit share system. Nearly all the comments perceived conceptual difficulties in the proposal. Among the considerations raised as presenting difficulties were the choice of a fixed capital recovery system, with the inherent difficulties posed by the selection of a fixed capital recovery factor and the selection of a point for termination of the preproduction period; the increased administrative requirements for both Government and industry, including the perceived problems associated with lowered incentives to early exploration or to formation of joint ventures; unitization of net profit share leases with fixed royalty leases; use of the proposed system in frontier areas, and frequency of its use; and the augmented role of the USGS in the administration of the fixed net profit share system. Other comments expressed a preference for a fundamentally different system of profit sharing, the investment account system, instead of the fixed capital recovery system proposed in the regulation. For reasons detailed below, DOE has chosen to adopt in this final regulation the proposed fixed capital recovery system with certain modifications, as the most efficacious and least burdensome means of implementing profit share leasing.

The third major portion of the comments addressed technical issues, most notably perceived shortcomings in the accounting procedures contained in the proposal. Several sets of comments contained detailed recommendations to remedy perceived flaws in the proposal, several from those respondents expressing greatest disapproval of the net profit share concept. The major shortcomings of the proposed regulation discussed in the comments centered on exclusion of various costs from the profit share accounts, and allocation of certain operating costs to overhead. DOE intends this regulation to provide lessees with incentives to early exploration and development. Insofar as possible, the final regulation defers to industry accounting practices as set out in procedures of the Council of Petroleum Accounting Societies of North America (COPAS). Deviations from COPAS procedures are basically due to the different purpose of this regulation from that of usual joint venture accounting because COPAS leaves allocation of certain contract factors (e.g. overhead rates) to negotiation by the joint venturers.

DOE has carefully reviewed all of the comments and considered them in redrafting this regulation. The discussion of the major comments which follows is divided into three sections: the foundation of the regulation, the structure of the fixed net profit share system, and the accounting procedures. The comments provided considerable assistance in the redrafting of the regulation, particularly with respect to many technical aspects of the accounting procedures.

B. Foundations of the Regulation

Most comments received from industry expressed some degree of opposition to the concept of leasing with a net profit share term in OCS leases. The degree of opposition varied, but appeared to stem from a general apprehension among firms engaged in OCS operations that introduction of a net profit share system might lead to decreased reliance upon the cash bonus-fixed royalty system at present in dominant use, and that the perceived burdens associated with any net profit share system might outweigh its beneficial aspects. Others questioned the existence of any beneficial aspects to the proposal, as compared with the traditional cash bonus--fixed royalty system. The comments also raised issues with regard to the foundations of the proposal, in theory and practice, and the assumptions used by DOE in formulating the proposal. The causal nexus between the proposed regulation and its intended effects was seriously doubted.

DOE appreciates the reservations of industry with regard to the introduction of a new bidding system. Nevertheless, DOE believes that rational objections to the concept of net profit

share are answerable. Relatively few comments were received taking serious issue with the conclusions reached in DOE's regulatory analysis although there were comments which criticized some of the assumptions of the regulatory analysis. Several comments stated that other analysis arrived at conclusions comparable to those in the DOE regulatory analysis. Other objections, unfortunately, were merely speculative assertions, unsupported by argument or data. As to these, DOE's analysis leads to different conclusions.

The regulatory analysis prepared by DOE for this regulation indicates that use of the proposed fixed net profit share system should result in a reduction of cash bonus bids for OCS leases. Several firms, however, took issue with this point, asserting that major oil and gas companies, due to their size, access to capital, and presumed economies of scale, can tolerate a lower return on investment. Therefore, these firms can afford not to discount cash bonus bids as much as smaller firms, to the detriment of these smaller firms in competing for OCS leases.

In response, DOE notes that this situation would represent perverse bidding behavior on the part of major companies. In their comments, companies have stressed the wholly rational process used in the formulation of bids for OCS leases, a process which generates a point bid or narrow range of bids and is based upon resource estimates for the tract, expected costs of exploration and development, and the value of subsequent payments to the Federal government for the lease. Companies have ascribed non-rational bidding behavior to other firms, but never to themselves. Nothing in the record, regulatory analysis, or bidding history has come to light to support the contention that net profit share leasing systems will lead to less rational bidding behavior on the part of firms than would occur under other bidding systems for OCS leases. The possibility of irrational bidding exists under present bidding systems, but while acknowledging the possibility, DOE doubts that such behavior is likely, or that such behavior is more likely when profit share systems are employed.

The general idea of competition for OCS leases, and especially its relation to the fixed net profit share system, received a good deal of discussion in the comments. Several comments asserted that competition for leases on the OCS is sufficient at present and, moreover, that no qualified company is presently precluded from participation, at least through joint ventures. Other comments questioned the necessary relationship of use of the fixed net profit share system and increased competition for OCS leases, instead citing such inhibiting factors as aversion to risk, inability to meet overall capital requirements, and lack of capability, as the major limitations on participation by firms in OCS lease sales.

DOE has never maintained that large front-end cash bonuses are the sole inhibiting factor to participation in OCS lease sales; however, large bonuses do figure importantly in a company's decision whether to participate in an OCS lease sale, as the comments also make clear. To the extent that a firm's decision to participate, either alone or as a part of a joint venture, depends on the initial cash bonus, use of fixed net profit share can operate to increase competition for OCS leases by reducing cash bonus amounts. The regulation makes no pretense of presenting a final solution to all problems associated with participation in OCS exploration and developemnt, such as access to all necessary capital or technical competence. It should be noted, however, that under a net profit share system, a lessee is able to recover expenses of exploration and development, plus a reasonable return on that investment, from production revenues prior to payment of any net profit share to the government. This differs significantly from a fixed royalty system, where contingent payments to the government begin with the first barrel of production.

Several additional assumptions used in the regulatory analysis were criticized in the comments as being erroneous or unwarranted. Major among them were sizes of average reservoir and bonus, timing of investment development costs, and constant capital recovery factors. A majority of comments pointed out that not all investment in development facilities takes place prior to commencement of production from a lease. The assumption in the regulatory analysis as to the timing of development investment costs was made for purposes of computer simulation, but in no way invalidates the conclusions reached in the regulatory analysis. In addition, as discussed more fully below, DOE has not assumed that no development costs are incurred after the onset of production, but merely that those costs bear a different relationship to the goals sought to be achieved by the regulation.

Neither do the results of the regulatory analysis depend for their validity on the assumptions made with regard to reservoir size, bonus, or constant capital recovery factor in a given OCS lease sale. The regulatory analysis examined a range of reserve sizes, from small (30 million barrels) to large (one billion barrels), to determine the impact of reservoir size on production incentivies created by the various systems.

Similarly, no a priori selection of system parameters (capital recovery factor and profit share rate) was assumed; rather, the whole range of these factors was examined to determine the combination most suitable for each system, given varying cost and resource size conditions. In theory, tailoring capital recovery factors to individual tracts operates to serve the pur-

poses of the regulation more closely, to the extent that resource and cost estimates are more accurately reflected in the combination of parameters applied to each tract.

C. Structure of the Fixed Net Profit Share System

A number of comments questioned whether the fixed net profit share system would achieve its intended objectives, but approached the question from the perspective of structuring a fixed net profit share system rather than the concept of net profit share itself. Comments from both industry and government admonished that adoption of a fixed net profit share system would not necessarily increase competition for OCS leases, maximize production, or foster development of marginal oil and gas fields, due to the manner in which DOE might choose to structure the concept of fixed net profit share. In general, the comments appeared to group around the choice of the fixed capital recovery system, the perceived administrative burden to industry and government associated with any form of net profit share, and the increased role of the USGS in the administration of the regulation.

Many related issues are subsumed within this characterization, but are either minor variations, or permutations, of these broader concerns.

1. Fixed capital recovery system. In the final regulation, as in the proposal, DOE has chosen to employ a fixed capital recovery system. This choice generated some approval and a good deal of criticism in the public comments. No attention was focused on an annuity accounts system; instead, there was much discussion of the relative merits and drawbacks of the fixed capital recovery system, as contrasted with an investment account system.

Stated briefly, the fixed capital recovery system as originally proposed accumulates costs incurred during OCS operations, without distinction as to whether they are capital or noncapital in nature, depending on when the expenses are incurred. After commercial production begins, exploration and development costs are recovered from production revenues.

As proposed, exploration and development expenses, those incurred prior to the onset of commercial production, receive a return designed to compensate for the capital at risk during the preproduction period. Costs that qualify for the allowance for capital recovery are charged against the NPSL accounts at a value equal to the amount of expenses increased by application of the capital recovery factor.

The capital recovery factor is unique to each lease and selected on the basis of cost and resource expectations. Recovery of costs incurred after the end of the preproduction period takes place on a dollar-for-dollar basis.

Evaluations of the fixed capital recovery system were divided, although even some supporters of this system recommended changes. Other comments found the proposal sufficiently deficient to suggest adoption of an investment account system instead. Criticisms of fixed capital recovery appeared to focus predominantly on two features of the system: difficulty in selection of the capital recovery factor and determination of the end of the period for which the capital recovery is allowed.

The fixed capital recovery procedure, which incorporates a capital recovery factor, is fundamental to the fixed net profit share system promulgated by this regulation. It is a mechanism for providing the lessee a return on the investment risk incurred to explore and develop a tract. A number of comments pointed out the difficulty inherent in determining a capital recovery factor that allows the lessee a return adequate to induce necessary investment, yet discourages uneconomic or wasteful investment resulting from a capital recovery factor set too high. Other comments questioned the feasibility of basing the capital recovery factor on cost and resource estimates made prior to the lease term, since both components are very uncertain until well into exploration and development. Wide discrepancies between USGS pre-sale estimates of minimum tract worth and high bids were cited as evidence of erroneous valuations by USGS; one comment frankly doubted the capacity of USGS to conduct this analysis. Several comments suggested that an investment account system would obviate need for a capital recovery factor. Also, these comments added that using a current market rate of interest, such as the prime rate, would suffice to establish the interest rate to apply to the investment account, variously defined. Such an interest rate would float in response to economic forces, and perhaps be more accurate than a capital recovery factor fixed in advance of a lease site.

Most of the comments endorsing the investment account system recommended its use on the basis of simplicitly and minimized administrative burden. However, the DOE regulatory analysis demonstrates that the investment account system suffers from intrinsic shortcomings that render it less efficacious than the fixed capital recovery system. In essence, an investment account approach permits application of an interest rate to expenses incurred, with interest being charged to the account even when no work is performed on the lease, as during periods of inactivity. With respect to its putative simplicity, while the investment account approach eliminates the need to determine at what point to terminate the period for which capital recovery is allowed, the auditing difficulties associated with administration of an investment account system are substantial. The requirement to track each expense, and assign each to

a discrete time period for the duration of the lease, represents a major undertaking and an auditing burden. Since the present value of any expense is "worth more" when incurred or booked one period earlier, there exists a major inducement to "front-end" development expenses, the very criticism leveled at the fixed capital recovery system. Due to compounding of interest, an investment account approach tends to provide more encourgement to such "front-end" loading of investment than a fixed capital recovery approach.

Moreover, selection of a proper interest rate for the investment account system poses no less a problem than selecting a capital recovery factor. Solving this dilemma by adoption of the prime interest rate, most often recommended in the comments, would institutionalize in the regulation a truly floating variable whose derivation is unrelated to the context of risk incurred by lessees on the OCS. The prime rate, in essence, represents a short-term cost of money to preferred customers, and floats continually in response to factors exogenous to OCS exploration and development, which constitute long-term investments.

In addition, several comments complained of including two variables in the fixed net profit share system, the capital recovery factor as well as the profit share rate. The investment account system has the same problem, since both an interest rate and a profit share rate must be selected. Use of any floating interest rate would introduce another real variable into profit share determinations. Calculations of bid amounts, taking future interest rates into account, might prove somewhat more difficult than at present. The comments were unable to demonstrate that an investment account approach could offer benefits exceeding those provided by a fixed capital system.

Rather than contend with the difficulties of the investment account system, despite its superficial attractiveness, DOE has chosen to retain the fixed capital recovery system in the final regulation, with modifications, recognizing that establishment of proper capital recovery factors is based on uncertainties and may be somewhat problematic. Capital recovery factors and net profit share rates will derive from many of the same estimates now employed to determine royalty terms and minimum acceptable bids for OCS leases. To the extent that the capital recovery factor is set inaccurately, undersirable consequences, such as overinvestment or impeded exploration, are possible. Capital recovery factors must be published in the Federal Register, and DOE anticipates that bidders will discount or increase bids as their estimates of costs and resources vary from those reflected in the capital recovery factor. As a truly fixed term in each lease, use of the capital recovery factor removes some uncertainty from planning bids or operations. The expected practice of discounting or increasing bids in response to net profit share rates and capital recovery factors is analogous to the same practice done in response to varying royalty rates.

Perhaps more than any other aspect of the proposed fixed net profit share system, the provision relating to the end of the preproduction period, that period during which expenses incurred would qualify for the allowance for capital recovery, engendered critical reaction in the comments.

Several comments reflected a mispreception that the preproduction period in the proposed regulation terminated at the onset of any production, regardless of volume or value, and expressed the consequent concern that major development expenses would be excluded from application of the capital recovery factor as a result of relatively insignificant amounts of production. This was never the intent of the proposed regulation. As defined in the proposal, production meant "commercial production", that is, the production of oil or gas in commercial quantities.

Many comments reflected the view that even the onset of commercial production would exclude too many legitimate development costs from eligibility for capital recovery, as it is possible that commercial production would begin from some wells on a platform prior to completion of all wells planned for the platform. The comments differed in their perception of the severity of this problem, as well as in their assessment of the likelihood of commercial production prior to the completion of all wells. The comments also reflected a concern that there would be an incentive to delay production in order to include more costs in the preproduction account, particularly where costs yet to be incurred were significant.

Most comments indicated a perference for commencing production as early as possible, to obtain a flow of revenue. As a consequence of this policy to go on-stream early on, considerable development and even some exploration activities may take place after commencement of commercial production, and the comments suggested that it was inequitable to treat post-production expenses differently from preproduction costs solely on that basis. Moreover, a number of comments pointed out that this treatment raised the prospect of front-end loading of investment, and distortion of accustomed development patterns.

Front-end loading would involve a lessee in funding as much exploration, development, and production activity as possible prior to the onset of commercial production, in order to qualify for inclusion in the allowance for capital recovery. However, to the extent that the regulation as originally proposed induces lessees to incur exploration and development expenses sooner. DOE views this incentive as

consistent with Congress's intent to induce timely and efficient production, as expressed in the Amendments.

In contrast to the concerns expressed with respect to the acceleration of exploration or development activities, some comments suggested that the regulation as proposed created an incentive to delay production in order for additional development expenses to gain preferred treatment in the allowance for capital recovery. DOE agrees that this potential existed under the proposal, but the degree or severity of any delay rests entirely on the relative magnitude of the expenses already incurred by the leassee, the duration of the production delay, and the loss in value represented by the reduced present value of revenues from production initiated at a later time. It is difficult to construct scenarios where, given the magnitude of the development expenses likely to have been booked prior to the time any commercial production could commence and the potential loss in present value of gross revenues from production delayed, any substantial delay could be advantageous to a lessee. Also, USGS enforcement of development and production plans, which note the planned onset of commercial production and which are approved in advance of any development activity, provides additional insurance against protracted production delays.

The primary reason for implementing the fixed capital recovery system is that it creates incentives for prompt exploration and development. These incentives result largely from the application of the capital recovery factor to capital invested for exploration and development. Under the proposed regulation, the lessee would be denied this incentive on certain expenditures if "commercial" quantities of production were realized before the completion of development. By passing, without dismissing their importance, questions such as how much production might occur prior to the completion of platform development, or (proportionately) the magnitude of originally intended development costs that might be incurred subsequent to producing "commercial" quantities, it seems imprudent to deny the capital recovery incentive to a lessee on the basis of minor amounts of production. Conversely, it is equally imprudent to provide unneccessary incentives. Under the original proposal, once a lease has achieved commercial production, additional incentives are logically unneeded, absent special circumstances. Normal incentives for profit will motivate subsequent development activity.

It should be emphasized that the purpose of the capital recovery factor is to provide an incentive for early and expeditious exploration and development of a lease and to provide for a sharing of the risks of exploration by the government. As exploration and development expenses are recovered from production revenue, the original jusitification no longer obtains to the same degree. Whatever impact the incentive is going to have has been provided, and the risks attendant upon exploration and development have decreased significantly. Therefore, a dollar-for-dollar balancing of revenues against costs is appropriate after production has come on-line.

To the extent that current income is being employed for development, the government should not be required to give a premium for that investment. To argue that every dollar invested deserves a premium recovery is to ignore the different purposes served by the allowance for capital recovery and the simple recovery of costs from current income. When current income covers current costs, the premium intended to compensate for the costs of carrying the investment over an extended period of time is no longer warranted.

In order to accommodate certain of the concerns expressed, DOE has made several changes in definitions and nomenclature, which accord more closely with DOE's perception of how the final regulation will operate in practice. The "preproduction period" of the proposed regulation has become the "capital recovery period" in the final regulation. This shift in name has been made because the period during which the lessee may recover its expenses incurred in exploration and development of the NPSL tract is no longer restricted to the onset of commercial production, but may extend beyond that point, in part at the discretion of the lessee. The term "production period" has been dropped from the final regulations as its utility has been obviated through the adoption of somewhat different accounting procedures from those contained in the proposed regulation.

DOE has also altered the concepts of the "allowance for capital recovery" and the "capital recovery factor" from the proposed regulation. As originally proposed, the allowance for capital recovery, computed by multiplying the capital recovery factor by eligible costs, included both the amount of investment at risk and the premium allowed such investment, and the capital recovery factor was therefore expressed as a number equal to or greater than 1.0. To accomodate the revised accounting procedures adopted in the final regulation, DOE has elected to define the allowance for capital recovery as including only the premium allowed investment at risk, and not the amount of investment itself. It should be noted, as one consequence, that the capital recovery factor only needs to be a number greater than zero.

DOE has analysed many different options for termination of the capital recovery period and has determined that some degree of flexibility should be provided in the regulation. In addition, for reasons of administrative convenience and to provide an objective, predetermined standard, DOE has determined to tie the end of the capital recovery period to the pro-

visions of the approved development and production plan for an NPSL.

As a consequence of the foregoing considerations, the final regulation provides that the capital recovery period ends not later than the time when the last well on the first platform specified in the development plan is completed and wellhead equipment installed, but may be terminated at such earlier time as the lessee may elect. In the event that the last well on the first platform proves dry, the capital recovery period will be deemed to end with the determination that the last well is nonproductive. In the event the development plan is not completed, the capital recovery period will end with the last activity completed on the first platform pursuant to the development plan. A further change has been made to the accounting system to provide that production revenue attributable to the capital recovery period will be entered as a credit in that period, and that revenues in excess of incremental costs will operate to reduce the debit balance outstanding in the NPSL capital account as described in more detail in the discussion of the changes to § 390.020.

The purpose of the above changes is to provide a certain degree of flexibility in the regulation without distorting the underlying objectives of the regulations. This flexibility will not necessarily result in a reduction in those accrued costs already eligible for favorable treatment or even in the loss of favorable treatment for those post-production development costs in excess of revenues accrued during the capital recovery period. The regulation permits the lessee to receive an allowance for capital recovery on accrued costs in the NPSL capital account until such time as the lessee determines that it is no longer economically sound to do so, that is, in most cases, at the point when incremental revenues equal and then exceed incremental costs. It is possible that an individual lessee, if projected future costs significantly exceed projected revenues for the same period, might choose not to terminate the capital recovery period. The flexibility in the final regulation will permit a lessee to include those significant post-production costs to the extent that they exceed revenues.

2. Administrative burden. Many comments expressed the view that the proposal would not increase competition, or attain its other objectives, due to the administrative burden placed upon lessees. DOE recognizes that any net profit share system represents a dramatic departure from bidding systems used in the past. Industry's evaluative and operational procedures will have to be adapted to the profit share system; this adjustment may require several lease sales employing the fixed net profit share system and experience implementing the accounting procedures before this adaptation is completed. The procedures incorporated into the final regulation attempt to minimize administrative, compliance, and auditing costs. DOE's efforts to minimize administrative costs begin with adoption of as many COPAS procedures as possible. Ultimately, however, the success of this regulation rests with the industry, whose negative predisposition with respect to the fixed net profit share system could be transformed into a disastrous self-fulfilling prophecy.

DOE does not dispute that some increased administrative costs will result from implementation of the fixed net profit share system, although it maintains reservations as to the apparent magnitude of the burden claimed to be associated with implementation. Most of the comments generally complained of the administrative costs to be shouldered by both industry and government, and highlighted undersirable effects that might flow from these added costs, without specifying the magnitude of the costs.

Paramount among the concerns expressed was the disproportionate effect that raising administrative costs would have on smaller firms, which might well be unequipped to handle the increase in workload without additional staff or other resources. It was asserted that smaller firms are therefore placed at a relative disadvantage with respect to major oil and gas producers, and net profit share tracts would become relatively less attractive to these firms. As a consequence, smaller firms might withdraw from competition for net profit share leases as sole bidders, if not as part of joint ventures. Provision of data to USGS was cited as a major cost factor, especially early in the implementation of the fixed net profit share system, until both industry and USGS gain experience in administration. Certain accounting procedures, notably record retention, yearly inventories, allocation of employee time, and audits, were also cited as unduly burdensome. DOE has attempted to minimize the magnitude of the administrative burden in the final regulation, and will review closely the performance of the regulation in light of actual experience.

DOE must concede, however, that the actual costs of administration to both industry and government remain largely indeterminate. In the interests of minimizing these costs, the final regulation contains a number of revisions in the accounting procedures from the original proposal, to align them more closely to COPAS practice and other industry standards. Requirements for record retention, for example, now approximate standards set by IRS for income tax purposes. Audit provisions have been revised to allow for audit of accounts for a period of three years, absent fraud or misrepresentation, which more closely accords with industry practice; and the regulation no longer requires yearly inventories. In this fashion, the administrative burden should be reduced

to little more than already exists in joint venture accounting.

Several comments predicted that the fixed net profit share system would lower incentives to formation of joint ventures, due to increased administrative workloads inherent in the accounting procedures. It was asserted that net profit share leases tend to inhibit formation of joint ventures relative to leases issued on a cash bonus-fixed royalty basis.

It is difficult to understand why implementation of the fixed net profit share system would act as an impediment to formation of joint ventures, in view of the accounting procedures incorporated into the regulation. The COPAS procedures were devised originally to allocate costs among partners in joint ventures, a use very similar to that made in the regulation. Although the accounting procedures deviate from COPAS guidelines in some respects, DOE feels that the overall structure of the accounting procedures in the final regulation should not constitute an impediment to joint ventures.

A corollary concern expressed in the comments is that a net profit share system will impede unitization, particularly where the proposed unit includes net profit share leases and fixed royalty leases. DOE is persuaded that such a situation would not render unitization difficult. The contention appears to make little sense, particularly since USGS will either require or approve a unit agreement before it is effective. Voluntary unitization among net profit share and royalty leases would seem to involve no more difficulty than among leases with different fixed royalties or among leases with sliding scale royalty and fixed royalty. Unitization is not directly addressed in the final regulation, except in the provision for allocation of joint costs and credits (§ 390.014(d)). Again, with regard to unitization, USGS represents the interests of the public, and will approve a unitization plan which comports with the objectives of the OCSLA, as amended, and this regulation.

Increased competition for OCS leases is an intended objective of the fixed net profit share system, and DOE remains sensitive to any aspect of the regulation that may operate to reduce competition, through increased costs of administration or lowered incentives to formation of joint ventures. Despite repeated assertions that the proposal seriously underestimated the costs involved in administration, no attempt to quantify the level of added costs is evident in the comments. Industry comments in the main disagreed with DOE's estimate of $50,000 to $150,000 for accounting system modification and $25,000 to $30,000 in annual administration costs, but offered little in its place. Ultimately DOE sees no reasons to alter its estimate of administrative costs to lessees, particularly in view of modifications from the proposal to the final regulation.

3. Role of the USGS. The fixed net profit share system necessarily calls for a somewhat greater involvement on the part of government, as a sharer in net profits, in the administration of this system, in contrast to the cash bonus-fixed royalty system. This aspect of the regulation received a significant amount of comment, most of it negative. Several comments characterized the role of the USGS in this regulation as unwarranted intrusion by the government into corporate business decisions, while one comment stated that the role of the USGS reduced the lessee to the status of a general contractor.

Under the final regulation, which replaces the Supervisor by the Director of USGS or delegate, the authority of the USGS to regulate substantive economic decisions has not been increased over its present level. However it is necessary to recognize that, in a very real sense, the USGS represents the interests of the public in the exploration and development of its resources and already has an active role in OCS decisions. As future sharer in net profits, USGS must ensure that any sharing arrangement make provision for monitoring expenses incurred during exploration, development, and production, in order to ensure an equitable division of net profits. As the agency most directly connected with operations on OCS leases the USGS is the logical choice to perform such monitoring.

In the proposed regulation, responsibility was vested in the USGS to make determinations on the allowability of certain costs, inventory, and performance of periodic audits. In addition, resource information provided by the USGS will be used in determining proper capital recovery factors and profit share rates.

Most of the criticisms directed at the role of the USGS in administering the fixed net profit share system seemed to center on provisions which authorize the USGS to approve certain investment and operating decisions of the lessee. Specifically, the proposed regulation would have permitted the USGS to interpret and implement guidelines for inventory, purchasing, and control of materiel; to recalculate net profit share payments based on determinations that expenses were improperly claimed or classified; to determine the point at which production in commercial quantitites begins; to establish maximum rental rates for equipment and facilities supplied by the lessee; to approve pricing of transferred or disposed materiel valued in excess of $100,000 on a current market basis; to establish charges for loading and unloading of tubulars; and to approve other costs not treated in the proposed regulation.

The criticisms considered these authorities unwarranted and unprecedented, and an intrusion by government into the daily business decisions of lessees. It was felt that approval by the USGS of certain expenditures might lead to disputes and operational delays, with consequent

deferrals of exploration and development. Several comments pointed out that the USGS must already approve plans for exploration, and for development and production, prior to actual operations. Also, operators must obtain a permit to drill each well on a lease. These plans and permits were suggested as means of obtaining general approval of expenses. Other comments stated that these plans and permits allow the government adequate control over OCS operations, and that audits provided the proper means for resolution of financial disputes. DOE has incorporated a modification of this approach into the final regulation.

DOE acknowledges that the responsibilities vested in the Director of USGS or delegate under the fixed net profit share system will probably affect certain operational decisions, although to an uncertain degree, and has made several changes in the regulation to reduce the Director's involvement to the minimum needed for effective administration. DOE has attempted to eliminate the potential for delay of exploration and development through administrative snarls. The time period between audits and inventories has been lengthened, more in accordance with industry practice. DOE recognizes that review of exploration and development and production plans, as well as permits, can afford the Director at least a detailed overview of anticipated expenses to be incurred by the lessee.

Many comments doubted the capacity of the USGS to perform the tasks assigned it under the proposed regulation, at least without a massive infusion of new personnel and funding. Several comments stated that the new personnel required by USGS to administer this regulation are precisely those with skills now scarce and most in demand by industry. Interestingly, the Department of the Interior in its formal comments only noted that the administrative role of the USGS warranted further delineation prior to promulgation. During the consultation process, DOE indicated the adequacy of its personnel to administer this regulation as promulgated.

The efficiency of USGS approvals and audit procedures to resolve disputes is a point well taken. However, DOE expects administrative snarls to be the exception rather than the rule. Particularly in comparison with other agencies, USGS has compiled a record of relative promptness in permit issuance and plan approval on the OCS. USGS staff have demonstrated considerable expertise and familiarity with OCS operations. The approval provisions that remain in the final regulation reflect a concern on the part of DOE that lessees understand, as early as possible, treatment of coasts by the USGS, in order to ameliorate disputes well in advance of audits, particularly in view of the lengthened period between audits. And, with respect to consideration of delay, it should be emphasized as well that the regulation requires approval of expenses by the Director only for purposes of inclusion in the NPSL capital account, and therefore chargeable in determining net profit share payments. The lessee retains absolute discretion to incur such additional costs as appear warranted. Also, no provision in the regulation requires approval of costs before they are incurred. Requests for approval after the fact are expected to be very common.

4. Other issues. A number of relatively tangential issues deserve mention. Several comments were critical of the fixed net profit share system for its anticipated impact on farmins and farmouts, expressing apprehension that smaller firms in the market would not be able to handle both the increased administrative workload and the profit share rate on top of the interest retained by the lessee; one comment predicted that no market for farmouts would exist on net profit share leases. DOE discounts this possibility, inasmuch as the situation in a prospective farmout arrangement under a net profit share lease differs only marginally from that under a lease with fixed royalty. In fact, a net profit share lease might make a more attractive farmin candidate, due to the ability of the lessee to recover accumulated costs. However, cognizant of the relative increase in administrative costs caused by the regulation, DOE has attempted to make clear that responsibility for recordkeeping and administration rests with the lessee, and not on the party taking the farmout (§ 390.030(a)).

There appeared often in the comments a statement that return to the public for its OCS resources has already proven more than fair during the 25 years of OCS operations; usually the assertion was made in connection with a suggested ceiling for profit share rates near the minimum, or a recommendation to establish a constant profit share rate for each OCS lease sale. Behind this statement, and underlying industry criticisms of risk-sharing by government, is an implicit conclusion that a net profit share system reduces the possibility of tapping a "bonanza" field, the reserves of which far exceed pre-sale estimates. Lessees may then apply revenues from "bonanza" fields to recoup costs of acquisition and operations on unsuccessful leases.

It has been suggested that with net profit share, because the government shares in each dollar of net revenue gained from production, the return to industry for tapping a "bonanza" field may be substantially reduced. This perception seems to provide a basis for recommendations that the fixed net profit share system allow the lessee to include expenses incurred in unsuccessful operations on other leases in the allowance for capital recovery on producing leases. DOE has chosen not to adopt this suggestion, although it acknowledges the diminished relative value of a "bonanza" field under

a net profit share lease. Risk-sharing by government carries with it the concomitant opportunity to share increased returns (to the public) realized from the large fields. Also, risk-sharing by government should reduce the impact of nonproductive leases, thereby reducing the need for substantial offsetting revenues.

D. Accounting Procedures

Nearly every facet of the accounting procedures devised to administer the proposed fixed net profit share system received scrutiny in the comments. DOE obtained a good deal of information and suggestions from the comments with regard to modification of the accounting procedures in the final regulation. The comments proved especially useful in recommending changes in audit and recordkeeping requirements by providing insight to operational joint venture accounting practices.

In its proposed form, the fixed net profit share system was structured to comport with industry accounting practice to the extent consistent with the rationale and purposes underlying the regulation. Alignment with standard industry accounting practice was seen by DOE as a way to minimize confusion in accounting for expenses and revenues resulting from OCS operations, thereby helping to reduce administrative costs to the lessee. Departures from industry practice in the main involved situations not covered under COPAS guidelines, or where the industry standards invited a negotiated, arms-length agreement by the parties, absent in this regulatory context. In these situations, USGS approval has been required.

On the basis of the comments, DOE has decided to implement a number of changes in the accounting procedures. Some of these changes became necessary due to the shift in the definition of the end of the capital recovery period, while other changes seemed reasonable and useful from the comments.

Some items raised in the comments on the accounting procedures have not been adopted for the reasons set out immediately below. A more complete discussion of changes incorporated into the accounting procedures follows in Section IV of this preamble.

1. Direct costs. Several recommendations were made in the comments for DOE to allow as direct costs certain items which the proposed regulation specifically disallowed from the NPSL capital account. The rationale offered for such inclusion seemed based on the contention that lessees should be able to charge the NPSL capital account for all expenses incurred during exploration and development, regardless of the difficulty in ascertaining their amounts or in ensuring that they were attributable to NPSL operations in the amounts claimed, or delays in exploration and production might result.

These claims remain unpersuasive to DOE. None of the comments challenged the reasoning that underlay exclusion of various costs. Exclusion of the cash bonus tends to reduce the level of cash bonus bids without distortion of production economics, as it represents a sunk cost. Interest is unallowable because the fixed capital recovery system will provide a return on investment at risk, without regard to the source of the capital employed.

Other costs were not allowed because they were considered inappropriate, not customary, or very difficult to allocate directly to a net profit share lease. Construction costs of onshore facilities and acquisition of real property, certain employee relocation costs, and fines and penalties levied by Federal agencies for regulatory violations are disallowed for these reasons; while the costs of maintaining a legal staff, taking of inventory, research costs (including in-house), and administration of employee benefit plans are intended to be covered by overhead. For reasons discussed in Section IV of the preamble, abandonment costs are allowable as a direct charge to an NPSL to the extent incurred before cessation of production and that there are offsetting production revenues. It should be noted that, in the case of research and development, personnel expenses may be allowable under § 390.011(b).

2. Legal expenses. Several comments noted an apparent discrepancy between the disallowance of the cost of a lessee's legal staff or outside attorneys and the allowance for the legal expenses of handling, investigating and settling litigation and claims, lien discharge, and payment of judgments or settlements, in connection with NPSL operations. The latter situation almost assuredly will involve the services of a legal staff, whether in-house or outside counsel. DOE considers the distinction one of allocability, fully analogous to the situation with regard to wages and salaries. Insofar as the services of a legal staff relate directly to NPSL operations, or are necessary to protect or recover NPSL property, such costs directly benefit or are incurred in support of an NPSL, and are therefore chargeable to the NPSL account. In the opposite circumstance, where the services of attorneys do not relate specifically to an NPSL, costs associated with such services are properly charged as overhead, and disallowed from the NPSL account. Moreover, in connection with costs of litigation against the Federal government, it is inappropriate for the government to pay a share of the costs through the NPSL profit share. If it so determines, it is within the discretion of the trial court to award attorney's fees and court costs in appropriate cases. Clarifications have been added to the final regulations to reflect these decisions.

3. Cash versus accrual accounting. DOE has

declined to adopt the recommendations which took issue with DOE's determination not to allow lessees to keep NPSL accounts on a cash basis. DOE believes that there is clear evidence that the industry operates on an accrual basis almost exclusively.

4. Monthly reporting requirement. Other comments faulted the proposed fixed profit share system for requiring monthly reports during the production period, asserting that the provisions represent an unduly onerous burden on lessees. DOE is receptive to means of minimizing reporting requirements in order to reduce administrative costs to lessees. However, in this instance, DOE has chosen to retain monthly reports after production revenues begin to accrue in the NPSL capital account, in the interests of providing a flow of information to the Director. Normal accounting practice results in a monthly balancing of accounts, and therefore merely requiring that this information be provided to USGS does not represent a significant burden. Review of monthly reports should assist in avoiding disputes, or in their resolution prior to audit. Reports are required only yearly prior to the onset of production, the period during which most costs will be accrued; however once revenues from production begin to accrue in the NPSL capital account, the final regulation provides for reports on a monthly basis, regardless of whether the capital recovery period has terminated. Except in the case of inventory, where 90 days had already been provided in which to file the report, DOE has lengthened the filing period from 45 days to 60 days after the end of each month. Monthly reports of production are similar to reporting provisions in USGS regulations and DOE expects that it may be possible to blend the various requirements into a single report.

5. Replacement costs. A small number of comments requested modification of the provision that excludes costs to repair or replace NPSL property, lost or damaged through willful misconduct or negligence on the part of the lessee, as allowable direct costs. These comments recommended insertion of the term "gross", before "negligence" so that costs incurred due to lessee's ordinary negligence might be allowable. DOE has elected not to adopt this suggestion, as the incentive to avoid negligent actions would be diminished.

6. Contract services. The proposed regulation allowed costs of contract services as a direct charge to the NPSL account to the extent that such services constituted necessary and proper NPSL operations or support for NPSL operations, and were performed in the NPSL project area. Contract services performed outside the NPSL project area were allowed only if the contract dealt exclusively with services benefitting the NPSL tract or NPSL operations. Several comments indicated that it is common industry practice to contract for routine services covering more than one tract, and therefore separate contracts for NPSL tracts are unnecessary and burdensome.

DOE is sensitive to assertions that aspects of this regulation might contribute to increasing administrative costs to lessees, and DOE acknowledges that contract services performed outside the NPSL project area may play an important role in exploration and development of the NPSL tract. The difficulty in this instance becomes one of allocating those costs incurred in order to benefit the NPSL tract, under the contract. Therefore, DOE has determined to modify this provision to permit a charge to the NPSL capital account for the costs of contract services which are applicable to NPSL operations and which are separately and specifically identified in the contract. Services not so identified and performed off the tract may not be included as a direct charge.

7. Rental charges. Rental charges for equipment and facilities owned by the lessee for use in NPSL operations received much discussion. The proposed regulation established a rental allowance for lessee-owned equipment and facilities, the charge to be based upon actual costs of acquisition, construction, and operation. This provision follows COPAS procedures very closely. DOE has chosen not to adopt a suggestion that rental rates be standard for all NPSL tracts, perferring instead to base rental charges on actual costs incurred by the lessee, subject to the ceiling of average commercial rates for similar equipment and facilities prevailing in the vicinity of the NPSL project area.

Despite assertions to the contrary, the proposed regulation did recognize depreciation as an element in establishing rental charges, and gave due consideration to shore-based facilities that might be built solely in support of NPSL operations. DOE does not see a reason for treating such facilities differently from those servicing both NPSL and non-NPSL operations, which are allowed as a rental charge. DOE also disagrees with the recommendation in several comments to apply the prime interest rate annually to the remaining undepreciated basis of such equipment and facilities, on the strength of the assertion that 8% is too low. Application of the prime rate presents difficulties of measurement; moreover, it does not comport with COPAS procedures in this situation. As a short-term money market rate, it would be inappropriate to employ it in a context of relatively long-term depreciation of assets. However, the final regulation does provide that the USGS Director is authorized to revise this rate in appropriate circumstances.

8. Insurance. The provision in the proposed regulation relating to allowance of insurance premiums and reimbursements is unchanged in the final regulation, although some criticism was directed towards procedures for crediting reim-

bursements to the proper NPSL accounts. In particular, the credit procedure covering reimbursement of damaged NPSL property was considered inequitable in the comments. In cases where a charge is incurred for lost or damaged NPSL property and that charge receives the allowance for capital recovery. DOE finds nothing inequitable in applying the capital recovery factor to the reimbursement, before crediting the NPSL capital account.

9. Relocation costs. For purposes of administrative convenience to both industry and government, DOE has elected to retain the provisions in the proposed regulation concerning employee relocation costs as more in accord with COPAS procedures than the suggestions, contained in several comments, to allow as direct costs all expenses associated with employee relocation that are the normal practice of the lessee. DOE believes that there may be considerable variance from lessee to lessee in the treatment of such costs, and therefore feels that a uniform standard should be established by the regulation to ensure equal treatment for purposes of the NPSL accounts.

10. Transportation costs. Several comments took issue with the limited allowance for transportation costs as a direct charge. There is no doubt that the provision in the proposed regulation is more restrictive than COPAS procedures on this point, in that COPAS limits such costs only with respect to movements between the NPSL project area and storage facilities which the lessee owns or controls. The final regulation retains the more restrictive version, and the limitation covers all movements of materiel between the NPSL project area and any storage facility, regardless of location or connection with the lessee. The comments received on this issue suggested allowance of all transportation costs related to movement of materiel, and removal of USGS from approving exceptions to the general rule. However, in the interest of certainty in allocating transportation costs that directly benefit NPSL operations, DOE has left this provision unchanged from the proposed regulation. Since all actual transportation costs are not allowed as direct charges to the NPSL account, retention of the Director is needed, for approval of exceptional cases.

11. Communications. According to many of the comments received, it is common practice within the industry to apportion communications facilities among operations because the expense and capacity of these facilities makes it uneconomical to maintain a separate system for each operation. The proposed regulation allowed as a direct charge the costs of acquiring, installing, operating, repairing, and maintaining communication systems between the NPSL tract and the lessee's nearest shore base facility. Suggestions appeared in the comments to allow pro rata apportioning costs associated with communications systems that serve several leases, rather than applying a rental charge, as in the proposed regulation. DOE considers the application of a rental charge as, effectively, a pro rata share of costs incurred in communications systems in support of NPSL operations. In arriving at rates for communications systems, the lessee may include any of the factors available in determining rental rates for equipment and facilities owned by the lessee, such as actual costs of acquisition and operation, labor, maintenance, repair, and depreciation. A separate provision for pro rata apportionment of costs incurred in communications systems is thus unnecessary. The regulation has been modified to include as a direct cost the cost of leasing communications facilities, as the comments indicated that this was common practice.

12. Environmental costs. In its proposed form, the fixed net profit share system allowed as a direct cost to the NPSL account expenses incurred in environmental or ecological surveys required by Federal or state agencies. This allowance is retained in the final regulation. DOE also proposed allowance of costs associated with pollution containment and removal equipment, as well as costs of actual control, cleanup, and consequent responsibilities of oil spills, and requested specific comment from the public on this issue.

Comment on inclusion of costs for control and cleanup of oil spills revealed a significant difference of opinion. Industry comments expressed the view that such costs are part of normal business expenses and thus should be allowed as a direct charge. A contrary view was expressed by government agencies like the Department of the Interior, which argued that such allowance would be inequitable. Other concerns focused on the propriety of the Federal government sharing in the cost of repairing damage to the NPSL tract caused by the negligence of the lessee.

In the final regulation, DOE has opted to allow control and cleanup costs as a direct charge to the NPSL capital account, in the belief that such allowance is not inequitable, except where the costs are incurred because of the negligence or willful misconduct of the lessee. DOE notes the existence of remedies such as the Offshore Oil Spill Contingency Fund to recompense injured parties for damages and penalties; assessments made on a per barrel basis in support of such Funds are also allowable as a direct charge to the NPSL capital account.

DOE notes in this connection that spilled oil falls within the definition of "production", and shall be taken into account in determining production revenues and net profit share payments due the Federal government.

13. Overhead. In the proposed fixed net profit share system, overhead was calculated at the rate of 4 percent applied to the preproduction account, and 10 percent of the balance of

the production account. DOE specifically requested comment on the accuracy of these rates. In the absence of alternatives demonstrably more useful, the final regulation incorporates these same rates.

Several comments from industry recommended application of the capital recovery factor to the overhead allowance, on the theory that overhead substitutes generally for costs incurred during exploration and development. Overhead, includible as a charge to the NPSL capital account is intended to cover interstitial components of expenses that, although very real are difficult to measure directly, and it estimates their magnitude at some percentage of applicable, identifiable costs.

Because overhead represents actual costs incurred, DOE has determined that it is appropriate that the capital recovery factor be applied to overhead.

Several issues regarding overhead were mentioned repeatedly in the comments. The first was that the regulations should provide for some recoupment of costs during periods of operational inactivity. Several comments indicated that operationally inactive periods may actually be times of intense analytical and preparatory work. Rather than a defect in the proposed regulation, DOE views this case as illustrative of the workings of the fixed net profit share system. Costs associated with analysis and preparation may be charged as direct to the NPSL capital account, or be reflected in the charge for overhead, depending on specific items. But no recoupment of such costs can take place until production begins.

A second issue associated with overhead maintained that the percentage allowance should allow for increased administrative burden to the lessee. Administrative costs form a component of overhead, and are included in the percentage allowance already established.

A number of comments called for a higher overhead percentage in frontier areas than in mature operating areas, like the Gulf of Mexico. DOE feels that application of a higher overhead rate in such areas is inappropriate, since the higher operating expenses of frontier regions will result in higher absolute dollar amounts of overhead. Direct costs are not more difficult to identify in frontier areas and, therefore, there is no reason that unidentifiable costs represent a higher percentage of direct costs in frontier areas than elsewhere.

IV. Changes in the Final Regulation

The final regulation differs from the proposed fixed net profit share system in significant respects, many of which have been discussed above. Due both to the comments received, and further analysis, DOE has been persuaded that the changes discussed in this section should serve the purposes of the regulation. Among the changes are a revised definition of production and a more precise means of measuring the end of the capital recovery period. The five NPSL accounts have been consolidated into a single NPSL capital account to ease administration, and accounting of expenses and calculation of the allowance for capital recovery have been shifted to a monthly basis. Changes have been made to the audit provisions and inventory requirements to bring them more into line with industry practice, and record retention provisions have been somewhat relaxed.

The discussion below follows changes in the regulation on a section-by-section basis.

§ 390.002 Definitions.

The definition of "Compensated personal absence" has been deleted, and replaced with "Lessee's cost of allowed employee absence", which comports more closely with COPAS Bulletin #15.

The definition of "cost" has been expanded to include accruals incurred in the conduct or in support of NPSL operations. This expansion came about in response to comments pointing out that NPSL accounts are required to be kept on an accrual basis, yet accruals had been omitted from the definition.

The definition of "cost pool" has been clarified through language making certain that the pool of costs, prior to allocation under § 390.014, may include costs from other leases, including non-NPSL leases.

The definition of "credit" has been amended, in order to accord more closely with the revised accounting procedures in the final regulation.

The definition of "G & G" has been modified to include "geochemical" and other similar investigations in response to recommendations from the comments.

The definition of "NPSL operations" now includes "final abandonment" costs, to reflect allowance of certain abandonment costs incurred while the lease is still producing as direct charges to the NPSL account.

The definition of "preproduction period" has been deleted, and replaced with "capital recovery period." It retains its conceptual meaning as the period from lease issuance until the time when the allowance for capital recovery will no longer be given to further costs incurred, but the end of the capital recovery period has become somewhat variable, and a matter left to the discretion of the lessee, within stated limits. See the discussion of § 390.020 for a detailed explanation of how the capital recovery period will now be terminated. DOE has undertaken this revision in response to criticisms in the comments regarding the preceived arbitrariness in the proposed regulation of closing the preproduction account at the onset of commercial production, and to reflect the revamping of accounting procedures.

The definition of "production" has been revised, as suggested in the comments, to follow the DOI definition of the term.

The definition "production period" has been deleted.

The definition of "production revenue" has been changed to reflect the amended definition of "production."

A definition of "Director" has been added.

The definition of "tract" has been modified to agree more closely with an extant DOE definition of the term, in 10 CFR Part 375.

§ 390.010 NPSL capital account.

There was a considerable amount of comment received suggesting elimination or consolidation of the five accounts proposed for NPSL operations. In particular, the net profit share payment account and the lessee's net profit share account attracted a good deal of criticism as cumbersome and unnecessary. It was asserted that establishment of these accounts might conflict with the lessee's usual accounting practices as well.

To simplify the required accounting procedures, DOE has decided to eliminate the five accounts enumerated in the proposed regulation and substitute a single NPSL capital account in their place. Debits and credits would be applied directly to the NPSL capital account, as incurred, along with the allowance for capital recovery and the overhead allowance. This change is intended to reduce the administrative burden associated with an NPSL, and reduce the costs of regulatory compliance, particularly for smaller companies.

§ 390.011 Schedule of allowable direct and allocable joint costs and credits.

1. Labor. A good deal of confusion was manifested in the comments on whether employees need be assigned permanently to NPSL operations for allowance as labor costs. Many comments were severely critical of the proposed regulation for its seeming disallowance of wages and salaries paid to employees not assigned permanently to an NPSL operation.

DOE never intended that employees had to be assigned permanently to an NPSL in order for the costs of their wages and salaries to be includible. As a general case, employees need be engaged in NPSL operations continually only for a specific period of time, such as month, week, or pay period. Their wages and salaries as well as other enumerated personnel costs are then includible.

A paragraph has been added to state a special case, where costs of wages and salaries for other than full-time NPSL employees may be charged to the NPSL capital account, to the extent that the lessee can substantiate such costs through time records. The general rule, however, appears to offer greater administrative ease to the lessee, and to reduce costs associated with administration of this regulation. In addition, the regulation does not permit inclusion of any associated personnel costs for employees not employed full time on NPSL operations.

In paragraph (b)(2), the term , "lessee's cost of allowed employee absence", has been substituted for "compensated personal absence", as more in keeping with COPAS provisions.

The percentage limitation on labor benefits in paragraph (b)(5) occasioned a good deal of criticism in the comments. Many comments pointed out that COPAS guidelines currently allow actual costs of labor benefits not to exceed 23% of wages and salaries. DOE has raised the percentage from the proposed 20% to the 23% figure, and added a provision to allow the USGS to revise this percentage from time to time. DOE fully expects that the USGS will rely on the percentage most recently recommended by COPAS in revising this rate.

2. Materiel. Paragraph (c) has been amended to make clear that only an amount of materiel sufficient for economical operations may be charged to the NPSL capital account.

3. Contract services. In paragraph (e), DOE has determined to modify the costs that may be charged to the NPSL capital account to include those costs of contract services performed at sites outside the NPSL project area that benefit the NPSL operations exclusively, and that are separately and specifically identified in the contract. One problem with including costs for services performed outside the project area under a contract covering more than the NPSL operations was the difficulty inherent in quantifying what portion of the cost of the contract was associated with the NPSL operations. Therefore, as an accommondation between the interests of including all legitimate costs and of certainty in the charging of costs, the final regulation only permits costs to be charged to the extent that the contract is sufficiently precise in distinguishing them.

4. Legal expenses. In paragraph (f), DOE has added language to clarify the alleged discrepancy between those legal expenses allowed as charges to the NPSL capital account, and those disallowed under § 390.013. Briefly, legal expenses directly attributable to NPSL operations may be charged to the NPSL capital account, while expenses not so attributable, such as having in-house or outside legal services available, may not be charged to the NPSL capital account. DOE considers these expenses to be appropriately compensated by the overhead allowance.

5. Rental of lessee-owned equipment and facilities. The charge for depreciation permitted to be included in establishing a rental charge for lessee-owned equipment and facilities in paragraph (g)(1) has been modified in

two respects. Depreciation may be calculated according to any generally accepted accounting method and the interest rate on undepreciated assets may be modified by the Director.

With regard to rate charges for automotive equipment under paragraph (g)(2), several comments recommended linking these rates to those established by the Petroleum Motor Transportation Association (PMTA), and not involving USGS in rate determination. While DOE has not adopted this recommendation, it does anticipate that the Director will take PMTA rates into consideration, with appropriate adjustments for areas to which those rates do not apply.

6. Damages and losses. Paragraph (h) has been modified to delete the requirement that the lessee notify the Director of all damages and losses. It appears that this represented an unusually burdensome requirement that did not provide a significant benefit beyond that which would be provided by periodic audits. In addition, it is assumed that the Director will be made aware of major damages and losses to the NPSL property and that, therefore, the requirement was unnecessary.

7. Taxes. Paragraph (i) now illustrates the types of taxes chargeable to the NPSL capital account. These taxes include severence, excise, ad valorem, and mineral taxes. As a form of excise tax, "windfall profits" taxes imposed pursuant to Pub. L. 96-223, are chargeable.

8. Communications. Paragraph (k) has been modified to permit the charging of the costs of leasing communications equipment and the list of covered communications systems has been expanded to include explicitly computer production controls for the NPSL operations.

9. Ecological and environmental. Paragraph (l) has been amended to include explicitly, as chargeable, assessments to funds and organizations which provide assistance in the event of oil spills or other environmental damage.

10. Audits. The original paragraph (m), relating to audit costs, has been deleted, since DOE has determined, as a result of comment, that it is appropriate for the government to conduct audits of NPSL operations.

11. Dry or bottom hole contributions. A new paragraph (m) has been inserted, to allow explicitly as chargeable, costs of dry or bottom hole contributions. A number of comments expressed the view that this allowance was desirable and measurable, but the proposed regulation did not mention these costs specifically. This paragraph has been added to remove any doubt.

12. Abandonment costs. DOE has added a new paragraph (n), to allow actual abandonment costs, those incurred on other than an accrual basis. The industry comments received were nearly unanimous in their recommendation that DOE provide some explicit allowance for abandonment costs. In the proposed fixed net profit share system, DOE disallowed abandonment costs, as difficult to estimate accurately. Instead, bidders were anticipated to incorporate estimates of abandonment costs in arriving at bonus bids for OCS leases. DOE continues to believe that estimated abandonment costs should not be permitted to accrue in the NPSL capital account.

The comments indicated that some abandonment costs are incurred prior to actual lease abandonment. Therefore, the approach taken in the final regulation permits charging of actual costs, to the extent incurred before the cessation of production, and to the extent that there are offsetting revenues. DOE recognizes that this will not permit the charging of all abandonment costs and still anticipates that bidders will discount bids based upon their estimates of the magnitude of abandonment costs not offset by revenues.

13. Other costs. Paragraph (n) in the proposed regulation has been renumbered (o) in the final regulation. A new provision has been inserted to deem as approved by the Director other costs to the extent they are separately identified in an approved development and production plan. This provision is expected to reduce administrative costs for both USGS and the lessee by not requiring approval by the Director for costs incurred in normal operations on a lease.

§ 390.012 Overhead allowance.

The exclusions from overhead charges contained in paragraph (c) of this section have been modified by deleting legal expenses incurred under § 390.011(f) and rental costs incurred under § 390.011(g) and by limiting the exclusion from the overhead allowance of injected substances to those reinjected substances originally produced on the lease.

§ 390.013 Unallowable costs.

Paragraph (j), disallowing abandonment costs, has been deleted, to reflect their allowance as charges to the NPSL capital account.

A new paragraph (j) has been added, to make clear that rentals on facilities, for which the lessee has charged investment costs to the NPSL capital account, are not allowable.

A new paragraph (k) has been added, to specify that costs incurred by the lessee prior to issuance of the NPSL, are not allowable.

§ 390.014 Allocation of joint costs and credits.

Paragraph (b)(2) has been amended to change the basis of allocation of wages and salaries from a well basis to a "reasonable and equitable" basis, since these costs may not be related to wells in many cases.

A new paragraph (d) has been added, to account for the allocation of costs and credits

where NPSL tracts are unitized with other tracts.

§ 390.015 Pricing of materiel purchases, transfers, and dispositions.

Paragraph (a)(3), the requirement for USGS approval of pricing on a current market basis for items costing in excess of $100,000, has been deleted.

Several comments indicated that no limit should be placed on this materiel, particularly since the $100,000 limit is rather low and exceeded often. Administratively, the USGS would be swamped and pricing decisions postponed for no pressing reason. The paragraph has been deleted to eliminate both the $100,000 limit and the need for the USGS approval and the final regulation relies instead on audits to remedy discrepancies.

§ 390.020 Calculation of the allowance for capital recovery.

The calculations described in this section have been modified to reflect the adoption, in the final regulation, of a single NPSL account, the NPSL capital account, instead of the system of five NPSL accounts used in the proposed regulation. This switch to a single account responds directly to the many comments that suggested that a five account scheme was unnecessarily complicated and cumbersome.

More importantly, the calculations described in this section have been modified to reflect the new approach adopted in the final regulation regarding the allowance for capital recovery. As noted earlier in this preamble, the determination of the preproduction period received the most negative comment. The comments were concerned that the proposed system would preclude favorable capital recovery treatment for any expense, development or otherwise, incurred after first commercial production. Unfortunately, little factual information was provided to illustrate the relative proportion of total development expenses typically incurred following first commercial production.

However, in an attempt to expand the opportunity for development expenses to receive favorable capital recovery treatment, the proposed preproduction period has been extended beyond the onset of first commercial production. Because the period for capital recovery treatment is no longer exclusively "preproduction", it has been renamed the "capital recovery period." In the final regulation, the lessee may at his discretion extend the capital recovery period beyond the onset of first commercial production until the sooner of two events occurs: (1) When the balance in his NPSL capital account changes from a debit balance to a credit balance, marking the point at which all expenses have been recovered through production revenues; or (2) when the last development well from the first platform specified in the development plan is completed and wellhead equipment installed. In the event that the last well proves dry, the end of the capital recovery period will be deemed to end at the date of determination that the last well is non-productive. Prior to either of these two events, the lessee may choose to terminate the capital recovery period by making this election in writing to the USGS; this election is irreversible.

Thus, the lessee may choose to initiate production while keeping the capital recovery period open. Revenue from production during the capital recovery period would be credited to the NPSL capital account until the end of the capital recovery period. To the extent that production revenues in a month during the capital recovery period exceed expenses incurred during the month, the excess revenues will offset previously accumulated expenses and reduce proportionately the previously "earned" capital recovery premium. The accounting mechanism for accomplishing this proportionate reduction, given the fact that under the single account system the allowance for capital recovery will already have been calculated for previously incurred costs, is to enter, in addition to the credit entry for the production revenues, a negative allowance for capital recovery which shall be the amount by which monthly revenues exceed monthly costs multiplied by the capital recovery factor.

These new provisions allow the lessee to end the capital recovery period at the point he believes most advantageous. More development expenses will receive capital recovery treatment, and as such there should be little if any incentive to delay production as expressed in the public comments. However, the requirement to credit production revenue against current expenses and to compute a negative allowance for capital recovery for any month in which revenues exceed allowable costs, provides some insurance that the capital recovery period will not be extended indefinitely.

§ 390.021 Determination of net profit share base.

This section describes the "accounting cycle" for an NPSL lease. It specifies accounting procedures and entries required to maintain the NPSL capital account. Because it relies on previous sections for such calculations as the allowance for capital recovery and the overhead allowances, it has been altered extensively to conform with the changes made to those sections.

Three changes partially discussed in earlier sections of the preamble, but which interrelate and which influence the structure of this section, are described here. First, the regulation now requires monthly entries in the NPSL capital

account throughout the life of the lease. At the end of each month, the appropriate allowance for overhead and the allowance for capital recovery (during the capital recovery period) must be calculated and entered, and the account balance determined. Also, when required during the capital recovery period, a negative allowance for capital recovery must be entered, if revenues and credits for a month exceed allowable expenses.

Second, the capital recovery factor has itself been changed from a number greater than 1.0 to a number greater than zero. This does not alter the original concept of providing a premium on all allowable expenses made during the capital recovery period. Rather, the change makes possible additional simplification in the accounting procedures. Now, the capital recovery factor represents the actual capital recovery premium that is debited to the NPSL capital account, which is made in addition to the debit for actual expenses.

Third, this section has been modified to reflect the additional inclusions permitted to the cost base for calculating the allowance for capital recovery. The regulation now provides for capital recovery treatment of the allowance for overhead during the capital recovery period.

§ 390.022 Calculation of net profit share payment.

Elements of this section have been altered to conform to the NPSL capital account specified in § 390.010.

§ 390.030 Maintenance of records.

Many comments objected to the requirement in proposed paragraph (b) to retain records from the issuance of the NPSL until five years after abandonment, arguing that the requirement imposed an additional administrative burden and that it did not comport with normal company practice. Several comments provided recommendations that DOE link record retention to audits to ameliorate the perceived burden in increased administrative costs. DOE has modified paragraph (b) to allow closing of books for audit adjustment purposes upon agreement by the auditor that there are no required adjustments or upon the lapse of thirty-six months from the due date or mailing date of the statement of account on an NPSL. Paragraph (b) of this section has been changed to require the maintenance of records for the same period as the account remains open for audit. However, ledger cards showing charges and credits to the NPSL accounts are to be maintained until thirty-six months after abandonment of the field.

§ 390.031 Reporting and payment requirements.

The deadlines for filing reports required in paragraphs (a), (b), and (e) of this section have been extended from 45 to 60 days after the end of the period covered in the report, in response to comments that the filing deadline was too short in the proposed regulation and imposed an unwarranted administrative cost on the lessee; the filing deadline for inventory reports in paragraph (d) remains at 90 days.

The interest on unpaid net profit share payments due the United States has been changed to the prevailing rates as published quarterly in the bulletin to the Department of the Treasury Fiscal Requirements Manual (TFRM). The interest charge provides compensation for the delay in receipt of the original amount due. Because of the volatility of interest rates, DOE has decided to adopt the quarterly interest rate of the Department of the Treasury, for applying interest charges to delinquent accounts. The rate will be published in a Treasury Bulletin to the TFRM issued prior to the first day of each calendar quarter, beginning in June 1980, for the quarter beginning July 1, 1980.

§ 390.032 Inventories.

Complaints in the comments regarding this section focused on the requirement for lessees to take inventory each year. This provision was considered unduly burdensome on the lessee as it departed from accepted industry practice.

DOE was sufficiently convinced of the validity of this contention to extend the period separating inventories to a maximum of three years, in paragraph (b). A caveat has also been added to this paragraph, in order not to bind the Director to an inventory taken in his absence, where clear indication of willful misrepresentation or fraud exists.

Paragraph (d) has been changed to delete the requirement that a list of overages and shortages be provided the Director and to require merely that it be available to the Director for the audit period.

§ 390.033 Audits.

The audit provisions in the proposed regulation attracted a good deal of comment and criticism, much of it well-founded. Industry comments were critical of the requirement to audit each NPSL every two years, and to hold the lessee liable for the costs of auditing. Industry practice in joint venture operations indicates that non-operating parties assume the cost of an audit deemed necessary from time to time. Audit costs are borne in the normal course of business by the parties requesting the audit; an additional benefit of this practice lies in the avoidance of a possible conflict of interest arising from payment of the auditor by the company audited.

DOE agrees that the auditor should be

employed, directly or indirectly, by the Federal government, which should bear the costs of the audit. The time requirement of paragraph (a) has been amended for greater flexibility to the Director and reduced administrative costs to the lessee; this paragraph now allows the government to initiate an audit within thirty-six months of the date of the statement to be audited, but not more often than annually, absent fraud or willful misrepresentation. Language has been added to paragraphs (a) and (b) to encourage cooperation between the government and non-operators in the calling and conduct of the audit, in order to reduce administrative costs.

Procedures for exceptions and adjustments in accordance with COPAS guidelines, except for cases in which such an exception or adjustment would result in a change in any net profit share payment, are outlined in new paragraph (c), and subsequent paragraphs of this section have been re-numbered.

§ 390.034 Redetermination and appeals.

Criticism of this section focused on the interest charged to redetermined net profit share payments. There were several requests for clarification as to the time from which the interest charge would be applied. Interest charges will be applied from the date on which the amount redetermined originally fell due. While DOE considers this part of paragraph (b) to be clear, it perhaps needs emphasis that this charge is not a penalty, but rather compensation for the delay in receipt of the original amount due. The interest rate has been changed to the prevailing rates as published quarterly in the bulletin to the Department of the Treasury Fiscal Requirements Manual.

V. NPSL Accounting Example

An example of the entries to the NPSL capital account together with the related computations of the overhead allowances and the allowance for capital recovery (ACR) is provided in this section. For illustrative purposes, the account is presented on a collapsed time basis with five monthly periods designed to illustrate the recording of transactions in various stages of the development and production cycle. DOE does not assume that the development and production cycle would occur in such a short time period.

The NPSL capital account as shown provides for three separate categories of costs. "ACR and Overhead Qualifying" costs are those costs that qualify for both the allowance for capital recovery and the overhead allowance. "ACR-only Qualifying" costs are those costs that qualify for the allowance for capital recovery but not for the overhead allowance. There are two cost elements that fall into this category: (1) Costs of contract services, and (2) the overhead allowance. The third column of the account includes the "Non-qualifying" costs. A column is provided for the total debits to the account. The credit side of the account includes the NPSL production revenues as well as other credits together with the appropriate allowances thereon.

In the first account, the first line entry represents the direct costs and the allocable joint costs which are properly chargeable to the NPSL capital account. Of the total $16,200 in costs, $11,400 qualify for both the allowance for capital recovery and the overhead allowance; $4,600 qualify for the capital recovery allowance but not for the overhead allowance (e.g., contract services); and $200 do not qualify for either allowance even though they are chargeable to the account (e.g., lease rental).

The first step in the end-of-month accounting procedures is to compute the overhead allowance. This is done by multiplying the qualifying expenditures by the 4% overhead allowance applicable to the capital recovery period. The resulting $456 is added to the column of costs that qualify for the ACR only, as well as to the total debit column. The allowance for capital recovery is computed by adding the fully qualifying costs to the ACR-only qualifying costs and multiplying the results by the capital recovery factor. The capital recovery factor is assumed to equal 0.30 for the example. The computation is then:

ACR = ($11,400 + $4,600 + $456) X .30 = $4,937

This amount is added to the non-qualifying costs column as well as to the total debit column.

The debits resulting from the overhead allowance and the allowance for capital recovery are added to the end-of-month account balance before computation of the monthly balance. The result is the total debits to the account. Any credits would be subtracted and the account balance would be obtained. Since there are no credits and no revenues, the end of month balance is now $21,593. This debit balance is carried forward to the next monthly accounting period.

Month 1.--NPSL Capital Account

	Debits				Credits
	ACR and overhead qualifying	ACR-only qualifying	Nonqualifying	Total debits	Revenues and other credits
Direct and allocable joint costs......	$11,400	$4,600	$200	$16,200	
Overhead allowance (4% X $11,400).....		456		456	
Allowable for capital recovery ($11,400 + $4,600 + $456) X .30.....			4,937	4,937	
Totals..........................	$11,400	$5,056	$5,137	$21,593	
Balance forward......................				$21,593	

In Month 2, the $21,593 balance is carried forward. The debits for the direct costs and allocable joint costs are made to the account as in Month 1. Of the $17,800 in current month costs, $10,100 qualify for both allowances, $7,400 qualify only for the capital recovery allowance, and $300 do not qualify for either allowance. The overhead allowance is computed by multiplying the $10,100 in qualifying costs by the 4 percent allowance. The resulting $404 is added to the ACR-only qualifying costs column and as a debit to the account in the total debits column.

The allowance for capital recovery in Month 2 is computed by taking the sum of the qualifying debits ($10,000 + $7,400 + $404, which equals $17,904) and subtracting the revenue credit ($4,200). The result $13,704 = ($17,904 - $4,200) is multplied by the capital recovery factor (0.30) to obtain the allowance of $4,111 (i.e., 0.30 times $13,704 + $4,111).

The computed allowance is then debited to the account. The sums of the debits and credits are computed as is the account balance. Since the balance is a debit, it is carried forward to the next month (Month 3).

Month 2.--NPSL Capital Account

	Debits				Credits
	ACR and overhead qualifying	ACR-only qualifying	Nonqualifying	Total debits	Revenues and other credits
Balance forward......................				$21,593	
Direct and allocable joint costs......	$10,100	$7,400	$300	17,800	$4,200
Overhead allowance (4% X $10,100).....		404		404	
Allowance for capital recovery ($10,100 + $7,400 + $404 - $4,200) X 0.30............................			4,111	4,111	
Totals..........................	$10,100	$7,804	$4,411	$43,908	$4,200
Balance forward......................				$39,708	

In Month 3, the total costs are $ 9,900, of which $6,700 are fully qualifying, $3,100 are ACR-only qualifying, and $100 are non-qualifying. The current month revenues exceed the current debits and therefore, if the lessee has determined to leave the capital recovery period open, would result in a negative ACR. This is calculated by taking the fully qualifying costs ($6,700), multiplying by the overhead allowance (4%) and obtaining the overhead allowance that would apply if the month were to be included in the capital recovery period. The resulting allowance is $268. The sum of the debits that would qualify for the ACR is $10,068 (i.e., $6,700 + $268 + $3,100). The revenue credit is $17,200. When the revenue is subtracted from the total debits, the base for the allowance for capital recovery becomes $--7,132 and the resulting allowance would be $--2,140 (i.e., $--7,132 times .30). To avoid taking a negative ACR, the lessee may elect to close the capital recovery period. For example purposes, it is assumed that the lessee has elected to close the capital recovery period as of the start of Month 3.

Therefore, the computations for Month 3 will include the overhead allowance at the post-capital recovery period rate of 10%. The accounting would proceed as follows. The direct costs and the allocable joint costs have been debited to the account as for Months 1 and 2. The revenue is credited as for Month 2. The costs that qualify for the overhead allowance amount to $6,700. The overhead allowance is computed by multiplying the $6,700 cost base by the overhead rate of 10%. The resulting $670 is debited to the NPSL capital account. Since the allowance for capital recovery no longer is applicable, totals can be taken immediately after computation of the overhead allowance. Total debits now amount to the sum of the $39,708 balance forward plus the current period allowable costs ($9,900) plus the 10% overhead allowance ($670). The total credits amount to $17,200. The account balance is a debit of $33,078 (i.e., $50,278 debits minus $17,200). Since the balance is a debit, it is carried forward to the next period (Month 4).

Month 3.--NPSL Capital Account

	Debits				Credits
	ACR and overhead qualifying	ACR-only qualifying	Nonqualifying	Total debits	Revenues and other credits
Balance forward......................	______	______	______	$39,708	______
Direct costs and allocable joint costs.......................	$ 6,700		[1]$ 3,200	9,900	$17,200
Overhead allowance: (10% X $6,700)..	______		670	670	______
Totals........................	$ 6,700	______	$ 3,870	$50,278	$17,200
Balance forward......................	______	______	______	$33,078	______

[1]Since this month is the month when the election to close the capital recovery period takes place, there is no need for a separate column for ACR-only costs, since there is no ACR. Although for reasons of consistency the original column headings are retained in this example, the account could at this point have only "Overhead Qualifying" and "Non-Qualifying" debit columns. The $3,200 represents the sum of the $3,100 of costs that would qualify for the ACR but not the overhead allowance had the month stayed within the capital recovery period plus the $100 in costs that would not qualify regardless of the election.

NOTE.--For illustration, the following entries demonstrate the accounting entries required for Month 3 if the lessee decided not to terminate the capital recovery period.

Month 3.--NPSL Capital Account

	Debits				Credits
	ACR and overhead qualifying	ACR-only qualifying	Nonqualifying	Total debits	Revenues and other credits
Balance forward......................				$39,708	
Direct costs and allocable joint costs........................	$6,700	$3,100	$100	$ 9,900	$17,200
Overhead allowance (6,700 X .04).....		268		268	
Allowance for capital recovery: ($6,700 + $3,100 + $268 - $17,200) X .3..............................			(2,140)	(2,140)	
Totals..........................	$6,700	$3,368	($2,040)	$47,736	$17,200
Balance forward......................				$30,536	

In Month 4, the NPSL capital account achieves payout. The $3,850 of overhead qualifying costs are charged to the account together with the $200 of non-qualfying costs. The overhead allowance of 10 percent is computed based on the $3,850 of qualifying costs and the overhead allowance is debited to the NPSL capital account. The total debits in the account now amount to the sum of the balance forward ($33,078) plus the current period costs ($4,050) plus the overhead allowance ($385). From this $37,513 total the revenues of $42,100 are substracted. The result is the account balance of $4,587 credit.

Since the balance in the account is now a credit, profit share payments are due the United States. The profit share payment is computed by taking the profit share base (i.e., the credit balance in the NPSL capital account after all entries and allowances for the month) and multiplying that balance by the profit share rate. Assuming a profit share rate of 40 percent, the profit share due the United States in Month 4 would be $1,835 (i.e., $4,587 times 40 percent). The profit share due the lessee would be the difference between the profit share base and the profit share due the United States or $2,752 (i.e., $4,587 less $1,835). The profit shares are debited to the NPSL capital account. As a result, the NPSL capital account balance is zero. The zero balance is carried forward to the next month, Month 5.

Month 4.--NPSL Capital Account

	Debits				Credits
	ACR and overhead qualifying	ACR-only qualifying	Nonqualifying	Total debits	Revenues and other credits
Balance forward......................				$33,078	
Direct and allocable joint costs........................	$3,850		$200	$ 4,050	$42,100
Overhead allowance ($3,850 X 10%)....			385	385	
Totals..........................	$3,850		$585	$37,513	$42,100
Balance before profit share..........					$ 4,587

Month 4.--NPSL Capital Account (Continued)

	Debits				Credits
	ACR and overhead qualifying	ACR-only qualifying	Nonqualifying	Total debits	Revenues and other credits
Profit Share					
U.S. Government (40%).............				$ 1,835	
Lessee (60%)......................				2,752	
Totals............................				$4,587	$4,587
Balance Forward...................				0	

In Month 5, there are $7,150 in new costs which are charged to the NPSL capital account. The overhead allowance of 10% is computed based on the costs that qualify for that allowance ($7,100). The resulting allowance of $710 is debited to the NPSL capital account. The total debits and total credits are computed and a balance obtained. If the balance were a debit, that debit balance would be carried forward to the next month. However, in this example, the balance is a credit ($47,600 revenues less $7,860 costs equals the credit balance of $39,740). The United States' profit share is computed by multiplying the $39,740 profit share base by the 40% profit share rate. The resulting $15,896 is debited to the account. The lessee's share is computed as the $23,844 difference between the profit share base and the United States' profit share. The account is debited for the amount of the lessee's profit share. As a result of these entries, the balance in the NPSL capital account is reduced to zero. The zero balance is carried forward to the next month.

Month 5.--NPSL Capital Account

	Debits				Credits
	ACR and overhead qualifying	ACR-only qualifying	Nonqualifying	Total debits	Revenues and other credits
Balance forward....................				0	
Direct costs and allocable joint costs............................	$7,100		$ 50	$7,150	$47,600
Overhead allowance (10% X $7,100)....			710	710	
Totals............................	$7,100		$760	$7,860	
Balance before profit share..........					39,740
Profit shares					
United States (40%).............				15,896	
Lessee (60%)....................				23,844	
Totals				$39,740	$39,740
Balance Forward					0

VI. Environmental Review

After reviewing this regulation pursuant to DOE's responsibilities under the National Environmental Policy Act of 1969 (Pub. L. 91-190, 83 Stat. 852 (42 U.S.C. 4321)), DOE has determined that the proposed action does not constitute a major Federal action significantly affecting the quality of the human environment. Therefore, DOE has determined that no environmental impact statement is required for this regulation.

Environmental impacts resulting from the use of the fixed net profit share bidding system are expected to be minimal. There are two sources of potential environmental impact. First, since the fixed net profit share system is expected to improve economic incentives for expeditious exploration and development of tracts, there could be an increase of this activity on profit share tracts in the sale area. Second, the fixed net profit share bidding system will improve economic conditions and incentives for developing and producing smaller oil and gas deposits. Thus, the use of this bidding system could result in increased levels of production from the sale area.

In either case, however, the use of the bidding system is expected to result in cumulative incremental increases in activity or production, but not major individual increases. Absolute rates of activity or ultimate levels of production are not expected to fall outside the ranges that should be considered during an environmental impact analysis for lease sales conducted with conventional leasing systems. Environmental impacts associated with using the fixed net profit share bidding system will, of course, be examined prior to each lease sale. Moreover, potential environmental impacts resulting from the use of this system will be con-considered prior to the selection of a leasing system for tracts in each sale.

Thus, to summarize, DOE believes that any environmental impacts attributed directly to the use of the fixed net profit share bidding system are minimal and inconsequential. Moreover, the rates of activity and levels of production that could result from the use of the fixed net profit share bidding system are well within the ranges that must be considered by the environmental impact analysis for each specific sale.

VII. Effective Date

Section 8 of the OCSLA requires that the rules governing the calculation of net profits under the fixed net profit share bidding system implemented by this regulation be established at least ninety days prior to any notice of lease sale. Section 8 also requires that the notice of lease sale be published not later than thirty days prior to a lease sale. Therefore, in order to be available for use in any lease sale, the procedures contained in this regulation must be established at least one hundred twenty days prior to the sale. DOI has scheduled an OCS lease sale for the second half of September 1980. In order that the fixed net profit share bidding system be available for use in that sale, DOE finds in accordance with 5 U.S.C. 553(d)(3) that there is good cause to make this regulation effective immediately. DOE further finds that there is good cause to make this regulation effective immediately in that there will be no impact from this regulation until after the thirty-day period otherwise required.

(Outer Continental Shelf Lands Act, ch. 345, 67 Stat. 462 (43 U.S.C. 1331 et. seq., 1953), as amended by Pub. L. 95-372; Department of Energy Organization Act. Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. 7101 et. seq., 1977), E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Chapter II of Title 10, Code of Federal Regulations, is amended as set forth below.

RUTH M. DAVIS,
Assistant Secretary, Resource Applications,
Department of Energy

MAY 14, 1980

2. Regulations, 10 CFR 390, Accounting Procedures for Net Profit Share Payments, 45 FR 36800, May 30, 1980.

PART 390--ACCOUNTING PROCEDURES FOR DETERMINING NET PROFIT SHARE PAYMENT FOR OUTER CONTINENTAL SHELF OIL AND GAS LEASES

Sec.

390.001 Purpose and scope.
390.002 Definitions.
390.010 NPSL capital account.
390.011 Schedule of allowable direct and allocable joint costs and credits.
390.012 Overhead allowance.
390.013 Unallowable costs.
390.014 Allocation of joint costs and credits.
390.015 Pricing of materiel purchases, transfers, and dispositions.
390.020 Calculation of the allowance for capital recovery.
390.021 Determination of net profit share base.
390.022 Calculation of net profit share payment.
390.030 Maintenance of records.
390.031 Reporting and payment requirements.
390.032 Inventories.
390.033 Audits.
390.034 Redetermination and appeals.

AUTHORITY: Sec. 205, Pub. L. 95-372, 92 Stat. 643 (43 U.S.C. 1337); sec. 302(b), Pub. L. 95-91, 91 Stat. 578-79 (42 U.S.C. 7152(b)).

§ 390.001 Purpose and scope.

(a) This Part 390 establishes accounting procedures for determining the net profit share base and calculating net profit share payments due the United States for the production of oil and gas from OCS leases.

(b) The procedures established by this Part 390 apply to any OCS lease issued by the Department of the Interior under a net profit share bidding system established by § 376.110(a)(4) of this chapter.

§ 390.002 Definitions.

For purposes of this Part 390: "Allowance for capital recovery" means the amount calculated according to procedures specified in § 390.020. This amount allows a premium for risk initially undertaken by the lessee and a return on investment made during the capital recovery period. It is provided in lieu of interest on equipment and materiel charged to the NPSL capital account.

"Capital recovery period" means the period of time that begins on the date of issuance of the NPSL and ends on the last day of the month during which the sooner of the following occurs:

(1) The lessee completes the last well on the first platform specified in the development and production plan originally approved by the USGS, with any approved amendments thereto, and installation of wellhead equipment. In the event the last well is dry, then the capital recovery period shall be deemed to have ended with the determination that the last well is non-productive;

(2) The balance in the NPSL capital account changes from a debit balance to a credit balance; or

(3) The lessee, at his election, chooses to terminate the capital recovery period. A decision to terminate the capital recovery period prior to the events specified in paragraphs (a)(1) and (2) of this definition shall be communicated in writing to the Director and shall be irrevocable.

"Controllable materiel" means materiel which at the time is so classified in the Materiel Classification Manual as most recently recommended by the Council of Petroleum Accountants Societies of North America.

"Cost" means an expenditure or an accrual incurred by a lessee in conducting NPSL operations.

"Cost pool" means a grouping of costs identified with more than one OCS lease, whether the leases are NPSLs or other types of leases.

"Credit" means a payment, rebate, reimbursement to a lessee, or other reduction in cost or increase in revenue attributable to NPSL operations.

"Direct cost" means any cost listed in § 390.011 that benefits only NPSL operations.

"Director" means the Director of USGS, Washington, D.C., or his delegate.

"Field employee" means an employee below a first level supervisor who is directly employed in the NPSL project area.

"First level supervisor" means an employee whose primary function in NPSL operations is the direct supervison of other employees and/or contract labor directly employed on the NPSL project area in a field operating capacity.

"G and G" means geological, geophysical, geochemical and other similar investigations carried out on the NPSL tract.

"Joint cost" means any cost listed in § 390.011 that benefits NPSL operations and one or more other operations of the lessee or an outside party.

"Lessee" means a person authorized by an OCS lease, or an approved assignment thereof, to develop and produce oil and gas, including all parties holding such authority by or through the lessee, and the person designated to conduct NPSL operations.

"Lessee's cost of allowed employee absence" means the lessee's cost of holiday, vacation, sickness, disability benefits, jury duty and other customary excused allowances.

"Materiel" means equipment, apparatus, and supplies.

"Net profit share base" means the end of the month credit balance in the NPSL capital account determined pursuant to § 390.021. The net profit share base is the production revenue remaining after subtracting all allowable costs and adding all allowable credits (including production revenue) in accordance with the procedures established by this Part 390.

"Net profit share payment" means the portion of the net profit share base payable to the United States.

"Net profit share rate" means the fixed percentage share of the net profit share base payable to the United States.

"NPSL" means a net profit share lease, which is an OCS lease that provides for payment to the United States of a fixed share of the net profits for production of oil and gas from the tract.

"NPSL operations" means all activities subsequent to issuance of the NPSL necessary and proper for the exploration, development, operation, maintenance, and final abandonment of the NPSL property.

"NPSL project area" means the NPSL tract, offshore facilities, and shore base facilities.

"NPSL property" means the NPSL tract, and materiel and offshore facilities acquired for use in NPSL operations and that are installed and/or used on the NPSL tract.

"NPSL tract" means a tract subject to an NPSL.

"OCS lease" means a Federal lease for oil and gas issued under the OCSLA.

"OCS lease sale" means the DOI proceeding by which leases for certain OCS tracts are offered for sale by competitive bidding and during which bids are received, announced, and recorded.

"Offshore facilities" means platform and support systems located offshore that are necessary to conduct NPSL operations, e.g., oil and gas handling facilities, living quarters, offices, shops, cranes, electrical supply equipment and systems, fuel and water storage and piping, heliport, marine docking installations, communication facilities, and navigation aids.

"Outside party" means any person who is not a lessee.

"Person" means person as defined in Part 376 of this chapter.

"Personal expenses" means travel and other reasonable reimbursable expenses of lessee's employees.

"Production" means all oil, gas, or other hydrocarbon products produced, removed, saved, or sold from the NPSL property. Gas and liquids of all kinds are included in production. Production includes the allocated share of production from a unit of which the NPSL is a part.

"Production revenue" means the value of all production attributable to an NPSL property, which value is determined in accordance with § 376.110(b) of this chapter.

"Railway receiving point" or "recognized barge terminal" means the location that a vendor would use in determining the sale price to the lessee of new materiel to be delivered to the NPSL project area.

"Reliable supply store" means a recognized source or common stock point for the particular materiel involved.

"Shore base facilities" means onshore facilities necessary for NPSL operation, including:

(1) Shore base support facilities, e.g., a receiving and trans-shipment point for materiel, staging area for shuttling personnel to and from the NPSL tract, a communication, scheduling, and dispatching center; and

(2) Shore base production facilities, e.g., pumps, separating facilities, gas plants, and tankage for production from the NPSL tract.

"Technical employees" means those employees having special and specific engineering, geological or other professional skills, and whose primary function in NPSL operations is the handling and resolution of specific operating conditions and problems for the benefit of NPSL operations.

"Tract" means land located on the OCS that is offered for lease through an OCS lease sale and that is identified by a leasing map or an official protraction diagram prepared by DOI.

§ 390.010 NPSL capital account.

(a) For each NPSL tract, an NPSL capital account shall be established and maintained by the lessee for NPSL operations. The NPSL capital account shall include debit entries for all allowable direct and allocable joint costs incurred during the term of the lease, appropriate overhead allowances permitted on these costs pursuant to § 390.012, and allowances for capital recovery calculated pursuant to § 390.020. The NPSL capital account shall be credited with production revenues attributable to the NPSL and any other credits arising from NPSL activities.

(b) The NPSL capital account shall be kept on an accrual basis.

§ 390.011 Schedule of allowable direct and allocable joint costs and credits.

The costs and credits specified in paragraphs (a)-(p) of this section may be charged direct, or allocated to NPSL operations, as appropriate, in accordance with § 390.014.

(a) Lease rental. The rent paid by the lessee for the NPSL tract is allowable.

(b) Labor. (1)(i) Salaries and wages of lessee's field employees, first level supervisors and technical employees employed in the NPSL project area in NPSL operations are allowable if such costs are not charged under paragraph (g) of this section.

(ii) Salaries and wages of technical employees within technical branches of the lessee's orga-

nization who are either temporarily or permanently assigned to, and directly employed in NPSL operations are allowable provided that such employees work "full time" on some particular aspect of NPSL operations or some specific technical problem. Excluded from this category are employees assigned a role in NPSL operations as a duty collateral with other duties that do not directly benefit NPSL operations.

(iii) Salaries and wages of technical employees within technical branches of the lessee's organization who are assigned technical tasks directly related to NPSL operations may be allowable. Costs may be charged to the NPSL if supported by adequate time records showing the nature of the task and the hours spent on that task.

(2) Lessee's cost of allowed employee absence paid to employees whose salaries and wages are chargeable to NPSL operations under paragraph (b)(1)(i) and (ii) of this section are allowable.

(3) Expenditures or contributions made pursuant to assessments imposed by governmental authority that are applicable to lessee's costs chargeable to NPSL operations under paragraphs (b)(1)(i) and (ii) and (b)(2) of this section are allowable.

(4) Reasonable personal expenses, including allowable relocation costs of employees whose salaries and wages are chargeable to NPSL operations under paragraph (b)(1)(i) and (ii) of this section and that are paid by the lessee or for which the employees are reimbursed under the lessee's normal practice are allowable except as limited by § 390.013(g).

(i) Allowable relocation costs include:

(A) Travel expenses, including transportation, lodging, subsistence, and reasonable incidental expenses of the employee and members of his immediate family and transportation of his household and personal effects to the new location.

(B) Other necessary and reasonable expenses normally incident to relocation, such as costs of cancelling an unexpired lease, disconnecting and reinstalling household appliances, and purchases of insurance against damages to or loss of personal property are allowable. Costs of cancelling an unexpired lease shall not exceed three times the monthly rental.

(C) Closing costs (i.e., brokerage fees, legal fees, appraisal fees, etc.) for the sale of the employee's actual residence when notified of the transfer are allowable; and

(D) Continuing costs of ownership of the vacant former actual residence being sold, such as continuing mortgage principal and interest payments, maintenance of building and grounds (exclusive of fixing-up expenses), utilities, taxes, property insurance, etc., after settlement date of lease or date of new permanent residence are allowable.

(ii) The combined total of costs listed in paragraphs (b)(4)(i)(C)-(D) shall not exceed 8 percent of the sales price of the property sold.

(iii) Section 390.013(g) specifies employee relocation expenses that are not allowable as a charge to NPSL operations.

(5) Lessee's current costs of established plans for employee's group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonds, and other benefit plans of a like nature that are made available to all of lessee's employees on an equitable basis, aplicable to lessee's labor cost chargeable to NPSL operations under paragraphs (b)(1)(i) and (ii) and (b)(2) of this section, are allowable. The amount of these charges shall be lessee's actual cost not to exceed 23 percent of the total charges under paragraphs (b)(1)(i) and (ii) and (b)(2) except that the Director may from time to time establish a different maximum percentage.

(6) Charges for expenses incurred under paragraph (b)(2)-(b)(5) of this section may be made in NPSL accounts on a "when and as paid" basis or by a percentage assessment method. If the percentage assessment method is used, it shall be based upon the lessee's actual cost experience expressed as a percentage of costs chargeable under paragraphs (b)(1)(i) and (ii) and (b)(2) of this section. Under either method the lessee's own cost of administering the plans and paying the salaries and benefits defined in this paragraph shall be excluded. In determining actual cost experience of an employee benefit plan, any dividend or refunds received that are applicable to insurance or annuity policies shall be used to reduce the cost of such policies.

(c) Materiel. (1) Materiel purchased or furnished by a lessee as NPSL property shall be charged or credited at amounts specified in § 390.015. The purchase and inventorying of materiel is subject to the conditions and provisions in § 390.032.

(2) Charges to an NPSL account shall be made only for such materiel purchased or furnished as NPSL property as is reasonably practical and consistent with efficient and economical operations. The accumulation of surplus stocks shall be avoided.

(3) Credit for salvaged or returned materiel shall be made to the NPSL capital account. When the amount originally charged qualifies for the allowance for capital recovery in § 390.020, the credit shall be calculated pursuant to § 390.021(a)(3).

(d) Transportation. Transportation of employees and materiel necessary for NPSL operations to, from, and within the NPSL project area, are allowable, but subject to the following limitations:

(1) If materiel is moved to the NPSL project area, no charge shall be made to NPSL operations for a distance greater than the

distance from the nearest reliable supply store, recognized barge terminal, or railway receiving point where like materiel is normally available, unless agreed to by the Director.

(2) If surplus materiel is moved from the NPSL project area, no charge shall be made to NPSL operations for a distance greater than the distance to the nearest reliable supply store, recognized barge terminal, or railway receiving point unless agreed to by the Director. No charge shall be made to NPSL operations for moving materiel to other properties owned by or under the control of a lessee, unless agreed to by the Director.

(3) In the application of paragraphs (d)(1) and (d)(2) of this section, there shall be no equalization of actual gross trucking costs of $200 or less, excluding accessorial charges.

(e) Contract services. Except when excluded by paragraph (f) of this section and/or § 390.013(c), the cost of services and utilities provided under contract by outside parties to the lessee and which constitute proper and necessary NPSL operations or support for NPSL operations, and rental charges paid to outside parties for the use of equipment used in the NPSL project area in support of NPSL operations, may be charged to NPSL operations subject to the following conditions and limitations:

(1) Contract services (including professional consulting services and contract services of technical personnel) that are entirely performed in the NPSL project area and benefit exclusively NPSL operations may be charged at the rates specified in the contract.

(2) Contract services (including professional consulting services and contract services of technical personnel) that are entirely performed in the NPSL project area and benefit the NPSL operations and operations on other tracts must be allocated among all tracts benefited and only that portion representing services benefiting the NPSL tract charged to NPSL operations.

(3) Contract services (including professional consulting services and contract services of technical personnel) that are performed at sites outside the NPSL project area may be charged to NPSL operations only if:

(i) The contracted services charged to the NPSL operations benefit only the NPSL tract or support NPSL operations;

(ii) The contract under which such services are provided deals exclusively with services benefiting the NPSL tract or NPSL operations, or the costs of the contract services which are applicable to the NPSL tract or NPSL operations are separately and specifically identified in the contract; and

(iii) Services specified in the contract relate to the resolution of specific technical problems confronting NPSL operations, or specific engineering design problems related to equipment or facilities required for NPSL operations. (4) The cost of any contract service related to research and development is specifically excluded, as are contract services calling for feasibility studies not directly related to specific engineering design problems or alternatives for equipment and facilities required by NPSL operations.

(f) Legal expenses. Expense of handling, investigating and settling litigation or claims, discharging of liens, payments of judgments and amounts paid for settlement of claims incurred in or resulting from NPSL operations, or necessary to protect or recover the NPSL properly are allowable, except those costs listed in § 390.013(f) as unallowable. This includes the salaries and wages of lessee's legal staff and the expense of outside attorneys who are assigned to matters described in this paragraph if supported by adequate time records showing the nature of the matter, its direct relationship to NPSL operations, and the hours spent on the matter.

(g) Rental of equipment and facilities furnished by lessee. (1)(i) The NPSL capital account shall be charged for the use of equipment and facilities owned by a lessee that are proper and necessary for NPSL operations, including shore base and offshore facilities and pipelines from the tract to shore base production facilities, and that are not NPSL property. Rental charges shall be made at rates based upon actual costs of acquisition, construction, and operation. Such rates may include labor, the cost of setting up and dismantling equipment, maintenance, repairs, other operating expenses, insurance, taxes, depreciation (calculated using a method consistent with generally accepted accounting principles, consistently applied) and a return on the remaining undepreciated basis not to exceed 8 percent per year, except that the Director may from time to time establish a different maximum percentage. Any cost of acquiring real property in excess of that reasonably required to support the facilities furnished for NPSL operations shall not be included in the costs used to establish these rates. Rates charged shall not exceed average commercial rates for equipment and facilities of similar nature and capability currently prevailing in the vicinity of the NPSL project area.

(ii) The term "equipment and facilities" is used in the broad sense to include equipment that may be mobile or semimobile and also installations that may be semipermanent or permanent in nature. Such equipment and facilities listed below shall be charged on the basis indicated.

Equipment/facilities	Basis of charge
A. Mobile equipment:	
Aircraft	Hour
Automobiles	Mile or hour
Trucks	Mile or hour
Tractors	Hour
Bulldozers	Hour
Mobile cranes	Hour
Trailor-mounted test separators	Hour
Truck-mounted cement mixers	Hour
Boats	Day or hour
House trailers	Day
B. Semimobile equipment:	
Drill rigs	Foot or day
Workover rigs	Hour
Pulling units	Hour
Derricks	Day
Drilling tender	Day
Barges	Day
C. Semipermanent installations:	
Skid-mounted separators	Day or volume
Skid-mounted compressors	Day or volume
D. Permanent installations:	
Compressor stations	Volume
Saltwater disposal wells	Volume or wells
Source water wells and supply systems	Volume
Roads	Wells
Production/drilling platform	Volume or wells
Canals	Wells
Dock	Wells
Oil storage and loading facilities	Volume
Gathering systems and pipeline	Volume
ACT systems	Volume
Laboratory services (excluding research work)	Hour or unit
Shore base production facilities	Volume
Shore base support facilities	Wells
E. Miscellaneous:	
Drill pipe	Foot or day
Casing setting tools	Day
Well testing equipment	Day

Equipment and facilities that are not listed shall be charged on a basis consistent with the nature of the use.

(2) In lieu of charges in paragraph (g)(1) of this section, the lessee may elect to use average commercial rates prevailing in the vicinity of the NPSL project area less 20 percent. For automotive equipment, the lessee may elect to use rates established by the Director. For other equipment for which no commercial rate exists, the lessee shall submit the basis for determining such costs to the Director for approval.

(h) Damages and losses to NPSL property. All costs necessary for the repair or replacement of NPSL property made necessary because of damages or losses incurred by fire, flood, storm, theft, accident, or other causes not covered by insurance, except those resulting from lessee's negligence or willful misconduct may be charged to the NPSL capital account. Any settlement received from an insurance carrier should be credited to NPSL operations when received.

(i) Taxes. All taxes, except income taxes, profit share payments, and taxes based upon income, that are assessed or levied upon or in connection with NPSL operations and which have been paid by the lessee are allowable. Allowed taxes shall include, but not be limited to production, severance, excise, ad valorem, and mineral taxes.

(j) Insurance. Net premiums paid for insurance required to be carried for NPSL operations are allowable. For NPSL operations in which the lessee may act as self-insurer for Workmen's Compensation and Employer's Liability, the lessee may include the risk under its self-insurance program in providing coverage under State and Federal laws and charge NPSL operations at lessee's cost not to exceed manual rates.

(2) NPSL operations shall be credited for all reimbursements for costs of damage to NPSL property or personal injury. Reimbursements for damaged NPSL property shall be credited as follows:

(i) If the damaged NPSL property is replaced or repaired, to the NPSL capital account charged for the cost of replacement or repair; or

(ii) If the damaged NPSL property is not replaced or repaired, to the NPSL capital account except that if the cost of the property originally qualified for the allowance for capital recovery in § 390.020, the credit shall be calculated pursuant to § 390.021(a)(3).

(k) Communications. Costs of leasing, acquiring, installing, operating, repairing and maintaining communication systems, including radio, microwave facilities, and computer production controls for the NPSL operations are allowable. If communication facilities systems serving the NPSL tract serve operations and/or facilities outside the NPSL project area, charges to NPSL operations shall be made as provided in paragraph (g) of this section or shall be allocated to NPSL operations in accordance with § 390.014.

(l) Ecological and environmental. Costs incurred in the NPSL project area as a result of

statutory regulations for archeological and geophysical surveys relative to identification and protection of cultural resources and other environmental or ecological surveys required by the Bureau of Land Management or other regulatory authority, may be charged to the NPSL capital account. Also, the costs to provide or have available pollution containment and removal equipment, including payments to organizations and/or funds which provide equipment and/or assistance in the event of oil spills or other environmental damage are allowable. The costs of actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations are allowable, except that a charge shall not be allowed for any such costs attributable to the lessee's negligence or willful misconduct.

(m) Dry or bottom hole contributions. The costs of dry or bottom hole contributions made to obtain information about the structure or other characteristics of the geology underlying the NPSL tract are allowable.

(n) Abandonment costs. Actual costs incurred in the plugging of wells, dismantling of platforms and other facilities and in the restoration of the NPSL project area shall be charged to the NPSL capital account only when incurred (i.e., not on an accrual basis), except that costs incurred after the cessation of production shall not be charged to the NPSL capital account. Abandonment costs in excess of offsetting revenues shall not form the basis of any claim against the United States.

(o) Other costs. Any other costs not covered in paragraphs (a)-(n) of this section and not disallowed by § 390.013 that are incurred by the lessee in the necessary and proper conduct of NPSL operation and are approved by the Director, are allowable. Approval of a plan of development and production for the NPSL tract by the Director shall be considered sufficient approval for these other costs provided they are separately identified in said plan of development and production. Such separate identification shall note the nature of these other costs and may include an estimate of their magnitude. Any cost approvals under this paragraph for which the specific amounts have not been itemized are presumed to be approved provided they fall within the limits for a prudent operator. Approval of costs under this paragraph shall be approval solely for the purposes of determining allowable costs and shall not preclude a subsequent adjustment at audit of the amount of such costs.

(p) Other credits. Credit shall be given to the NPSL capital account, depending on when it is incurred, for NPSL property leased or used in non-NPSL operations, for the sale of information derived from test wells and G and G, and for any and all amounts earned or otherwise due lessee as a result of NPSL operations.

§ 390.012 Overhead allowance.

(a) During the capital recovery period the overhead allowance shall be calculated on a percentage basis at the rate of 4 percent of allowable direct and allocable joint costs charged to the NPSL capital account, exclusive of costs specified in paragraph (c) of this section. This overhead allowance shall be debited to the NPSL capital account in accordance with § 390.021(b)(2).

(b) For each month after the end of the capital recovery period, an overhead allowance shall be calculated on a percentage basis at the rate of 10 percent of allowable direct and allocable joint costs charged to the NPSL capital account, exclusive of costs specified in paragraph (c) of this section. This overhead allowance shall be debited to the NPSL, capital account in accordance with § 390.021(c)(2).

(c) Overhead shall not be charged on the value of:

(1) Lease rental (§ 390.011(a));

(2) Contract services (§ 390.011(e));

(3) Taxes (§ 390.011(i));

(4) Re-injected hydorcarbons, originally produced from the NPSL tract, that are charged under § 390.011(c); and

(5) Credits for materiel charged under § 390.011(c) that are salvaged, returned, or used for the benefit of non-NPSL operations.

§ 390.013 Unallowable costs.

The following costs shall not be charged as direct or joint costs to NPSL operations:

(a) Bonus payments to the United States;

(b) Interest (except as permitted under § 390.011(g));

(c) Depreciation, depletion, amortization, or any other charge for capital recovery for materiel charged to the NPSL capital account under § 390.011(c), except as explicitly provided by the allowance for capital recovery calculated according to § 390.020;

(d) The cost of taking inventory;

(e) Research and development costs;

(f) The following legal expenses:

(1) The costs of litigation against the Federal government;

(2) Fines or penalties levied by any Federal agency;

(3) Settlement of claims or other litigation resulting from the lessee's violation of regulatory requirements or negligence; and

(4) The cost of the lessee's legal staff or expense of outside attorneys, except as explicitly allowed under § 390.011(f);

(g) The following employee relocation costs (whether incurred by the employee or the lessee):

(1) Loss on the sale of a home;

(2) Purchase price of a home in the new location;

(3) Payments for employee income taxes incident to reimbursed relocation costs; and

(4) Any relocation cost in connection with an employee move that is for the primary benefit of the lessee's non-NPSL operations;

(h) The lessee's own cost of administering employee benefit plans;

(i) The cost of acquiring or constructing shore base facilities and real property improvements that are charged to NPSL operations on a rental basis under § 390.011(g);

(j) Rentals on any facilities, the investment costs of which have been charged either directly or as allocable joint costs, to the NPSL capital account; and

(k) Pre-NPSL expenditures.

§ 390.014 Allocation of joint costs and credits.

(a) Joint costs shall be grouped in cost pools for allocation to NPSL and non-NPSL operations in reasonable proportion to the beneficial or causal relationship which exist between a specific cost pool and the operations. That portion of a joint cost pool that may be allocated to NPSL operations is called an allocable joint cost.

(b) The following allocation principles apply in allocating joint costs:

(1) G & G. G & G shall be allocated on a line mile per tract basis.

(2) Wages and salaries. Wages and salaries that are not charged as direct on the basis of time spent on a particualr job shall be allocated on a reasonable and equitable basis.

(3) Compensated personal absence, payroll taxes and personal expenses. These items shall be allocated on the same basis as wages and salaries.

(4) Transportation costs. Transportation costs for employees that are not charged direct shall be allocated on the same basis as their wages and salaries.

(c) Joint credits shall be allocated in the same manner as joint costs.

(d) When the NPSL is made a part of a unit, the allowed costs shall be charged to the NPSL capital account on the basis specified in the unit operating agreement as approved by the Director. Revenues and other credits shall be made to the NPSL accounts on the same basis as specified in the approved operating agreement. Joint costs of an NPSL and a non-NPSL tract that are adjacent to one another and are on the same structure shall be allocated on a basis approved by the Director.

§ 390.015 Pricing of materiel purchases, transfers, and disposition.

(a)(1) Purchased materiel. Except as provided in paragraph (a)(2)(i) of this section, materiel purchased for use in NPSL operations shall be charged to NPSL operations at the price paid, after deduction of any discounts received. Should any purchased materiel be defective or returned to a vendor for other reasons, the credit shall be allocated to NPSL operations when received by the lessee in accordance with § 390.011(c)(3).

(2) Transferred and disposal materiel. An item of materiel, which is acquired by the lessee for use in NPSL operations by means other than purchase or disposed of by any means, shall be priced according to this subparagraph:

(i) Condition A (New) Materiel: (A) Tubular goods, except line pipe, shall be priced at the current market price in effect on date of movement on a minimum carload or barge load weight basis, regardless of quantity transferred, equalized to the lowest published price "free on board" (f.o.b.) railway receiving point or recognized barge terminal nearest the NPSL tract where such materiel is normally available.

(B) Line Pipe.

(1) Movement of less than 30,000 pounds shall be priced at the current price in effect at date of movement, as listed by a reliable supply store nearest the NPSL tract where such materiel is normally available.

(2) Movement of 30,000 pounds or more shall be priced under the provisions for tubular goods pricing in paragraph (a)(2)(i)(A) of this section.

(C) Other materiel shall be priced at the current price in effect at date of movement, as listed by a reliable supply store or f.o.b. railway receiving point nearest the NPSL tract where such materiel is normally available.

(ii) Condition B (Good Used) Materiel. Materiel in sound and serviceable condition and suitable for reuse without reconditioning:

(A) Materiel transferred to the NPSL project area shall be priced at 75 percent of current Condition A price.

(B) Materiel transferred from the NPSL project area shall be priced:

(1) at 75 percent of current Condition A price, if the materiel was originally charged to NPSL operations as Condition A materiel, or

(2) at 65 percent of current Condition A price, if the materiel was originally charged to NPSL operations as Condition B materiel at 75 percent of current Condition A price.

(iii) Conditions C and D (Other Used) Materiel—(A) Condition C. Materiel that is not in sound and serviceable condition and not suitable for its original function until after reconditioning shall be priced at 50 percent of current Condition A price.

(B) Condition D. Materiel no longer suitable for its original purposes but suitable for some other purpose shall be priced on a basis commensurate with its use and comparable with that of materiel normally used for such other purpose. If the materiel has no alternative use it should be priced at prevailing prices as

scrap.

(iv) Obsolete Materiel. Materiel that is serviceable and usable for its original function and has a value less than Condition A, B, or C materiel may be valued at a price agreed to by the Director. Such price should be the equivalent of the value of the service rendered by such materiel.

(b) Pricing conditions. (1) Loading and unloading costs shall be charged at a rate of 15 cents per hundred weight, or such other rate as may be set by the Director, on all tubular goods movements, in lieu of loading/unloading costs sustained, when the actual hauling costs of such tubular goods is equalized under provisions of § 390.011(d).

(2) Materiel involving erection costs shall be charged at the applicable percentage of the current knocked-down price of new materiel.

(c) When materiel subject to paragraphs (a)(2)(ii)(iii) of this section is transferred, the cost of reconditioning shall be borne by the receiving party.

§ 390.020 Calculation of the allowance for capital recovery.

(a) For purposes of this section, the cost base for the allowance for capital recovery in a particular month shall consist of the sum of:

(1) All allowable direct and allocable joint costs chargeable to the NPSL capital account during the month less any costs specified in § 390.012(c); plus

(2) The value of contract services chargeable to the NPSL capital account during the month pursuant to § 390.011(e); plus

(3) The capital recovery period overhead allowance, calculated in accordance with § 390.012(a), that is chargeable to the NPSL capital account for the month; less

(4) Production revenues and other credits received during the month.

(b) If the cost base for a month is greater than zero (that is, if the sum of the charges specified in paragraphs (a)(1)-(3) of this section exceeds the value of production revenues and other credits), the allowance for capital recovery shall be calculated by multiplying the cost base by the capital recovery factor, and shall be debited to the NPSL capital account as specified in § 390.021(b).

(c) If the cost base for a month is less than zero, the allowance for capital recovery for the NPSL capital account shall be calculated by multiplying the resulting negative cost base by the capital recovery factor. The negative product of this calculation shall be debited to the NPSL capital account as specified in § 390.021(b).

(d) No allowance for capital recovery shall be calculated on the charges or credits related to any time period after the end of the capital recovery period.

§ 390.021 Determination of net profit share base.

(a) During each month of the lease term, the NPSL capital account shall be:

(1) Debited with allowable direct and allocable joint costs;

(2) Credited with an amount reflecting the production revenues for the month, calculated in accordance with § 390.011(b) of this chapter;

(3) Credited with amounts properly credited back to the NPSL capital account as specified in § 390.011(p). Credits associated with charges to the NPSL capital account during the capital recovery period, however, shall first be increased by the value of the credit multiplied by the recovery factor, before crediting that sum to the NPSL capital account.

(b) At the end of each month of the lease term during the capital recovery period:

(1) The transaction specified in paragraph (a) of this section shall be made to the NPSL capital account.

(2) The capital recovery period overhead allowance shall be calculated in accordance with § 390.012(a) and debited to the NPSL capital account.

(3) The allowance for capital recovery shall be calculated in accordance with § 390.020 and the allowance debited (or the negative allowance debited, as appropriate) to the NPSL capital account. (A debit entry of a negative allowance for capital recovery shall have the same effect as a credit entry of the absolute value of the allowance for capital recovery.)

(4) The balance in the NPSL capital account shall be calculated. If, as a result of the accounting transactions described in paragraphs (b)(1)-(3) of this section, there is a credit balance in the NPSL capital account, the capital recovery period will be considered terminated as of this month. The credit balance will be forwarded to the next month, which will be the first month for which a profit share payment is due.

(c) At the end of each month of the lease term following the end of the capital recovery period:

(1) The transaction specified in paragraph (a) of this section shall be made to the NPSL capital account.

(2) An overhead allowance shall be calculated in accordance with § 390.012(b) and debited to the NPSL capital account.

(3) The balance in the NPSL capital account shall be calculated.

(d) If, as a result of the accounting transactions described in paragraph (c) of this section, there is a credit balance in the NPSL capital account, this credit balance is the net profit share base for that month. The opening debit and credit balances in the NPSL capital account for any month following a month in which there is a credit balance in the NPSL

capital account (except as provided in paragraph (b)(4) of this section) shall be zero.

(e) If, as a result of the accounting transactions described in paragraph (b) or (c) of this section, there is a debit balance in the NPSL capital account, this debit balance shall be the opening debit balance in the NPSL capital account for the following month.

(f) Any credit balance in the NPSL capital account shall become the net profit share base as described in this section. Any debit balance in the NPSL capital account shall be maintained only insofar as necessary for the determination of profit share payments. Such debit balance shall not represent a claim against the United States.

§ 390.022 Calculation of net profit share payment.

The net profit share payment shall be calculated by multiplying the net profit share base calculated in accordance with § 390.021 by the net profit share rate. The net profit share payment shall be paid to the United States in accordance with § 390.031.

§ 390.030 Maintenance of records.

(a) Each lessee subject to this Part 390 shall establish and maintain such records as are necessary to determine for each NPSL:

(1) The volume and disposition of all oil and gas production saved, removed or sold for each month;

(2) The value of all oil and gas production saved, removed or sold for each month;

(3) The amount and description of costs and credits to the NPSL capital account;

(4) The amount and description of all costs of acquisition, construction, and operation of equipment and facilities furnished by the lessee and charged to the NPSL capital account under § 390.011(g). Such records shall include worksheets or other documents that indicate the method used to calculate the amount of each charge made under § 390.011(g);

(5) The cumulative balance of costs and credits to the NPSL capital account; and

(6) The inventory of materiel.

(b) The ledger cards showing the charges and credits to the NPSL capital account shall be maintained until thirty-six months after the cessation of NPSL operations by the lessee. All other documents, journals and records shall be maintained for thirty-six months from the due date or date of mailing of the statement of account on an NPSL, whichever comes later, except that nothing in these regulations shall limit the time of investigation or the need to produce records when prima facie evidence of fraud or willful misconduct is obtained with respect to the government's interest in the NPSL.

§ 390.031 Reporting and payment requirements.

(a) Each lessee subject to this part shall file an annual report during the period from issuance of the NPSL until the first month in which production revenues are credited to the NPSL capital account. Such report shall list the costs incurred, including allowances applied, credits received, and the balance of the NPSL capital account. Not later than 60 days after the end of the first month in which production revenues are credited to the NPSL capital account, a final report relating to the period shall be filed.

(b) Beginning with the first month in which production revenues are credited to the NPSL capital account, each lessee subject to this Part 390 shall file a report for each NPSL, not later than 60 days following the end of each month, containing the following information for the month for which the report is filed:

(1) The volume and disposiiton of all oil and gas production saved, removed or sold;

(2) The production revenue;

(3) The amount and description of all costs and credits to the NPSL capital account;

(4) The balance of the NPSL capital account; and

(5) The net profit share base and net profit share payment due the United States and the monthly profit share of the lessee.

(c) Each lessee subject to this Part 390 shall submit, together with the report required by paragraph (b) of this section, any net profit share payment due the United States for the period covered by the report.

(d) Each lessee subject to this Part 390 shall file a report not later than 90 days after each inventory is taken, reporting the controllable materiel on hand, acquired, transferred or used.

(e) Each lessee subject to this Part 390 shall file a final report, not later than 60 days following the cessation of production, together with the appropriate net profit share payment, indicating the remaining balance and costs and credits to the NPSL capital account for the period.

(f) Reports required by this section shall be filed with the Director, either separately or as part of the reports that are currently filed.

(g) Interest shall be calculated at the prevailing rate or rates as published in the Bulletin to the Department of the Treasury Fiscal Requirement Manual in effect for the period or periods over which the net profit share payment is owed, compounded monthly, on the amount of a net profit share payment, from the due date (60 days following the end of each month for which the payment was due) of a net profit share payment until such payment is received by the United States.

§ 390.032 Inventories.

(a) The lessee is responsible for NPSL materiel and shall make proper and timely cost and credit notations for all materiel movements affecting NPSL property. The lessee shall provide only such materiel as may be required for immediate use or is consistent with practical, efficient, and economical operations. The accumulation of surplus stocks shall be avoided by proper materiel control, inventory and purchasing. The lessee shall make timely disposition of idle and surplus materiel through sale.

(b) At reasonable intervals, but at least once every three years, inventories of controllable materiel shall be taken by the lessee. Written notice of intention to take inventory shall be given by the lessee at least 30 days before any inventory is to be taken so that the Director may be represented at the taking of inventory. Failure of the Director to be represented at an inventory shall bind the Director to accept the inventory taken by the lessee, except in the case of willful misrepresentation or fraud.

(c) Inventory shall be valued with any generally accepted accounting method used by the lessee to value the same materiel for financial or income tax reporting purposes, provided that the method is consistently applied throughout the life of the materiel.

(d) Reconciliation shall be made of a physical inventory with the NPSL capital account by the lessee, and a list of overages and shortages shall be available to the Director for audit as provided in § 390.033. Inventory adjustments of controllable materiel shall be made by the lessee to the NPSL capital account for overages and shortages. Controllable materiel removed from physical inventory that has not been credited to NPSL operations under § 390.015(a)(2) shall be credited to NPSL operations at its original value, except that when the cost of the materiel originally qualified for the allowance for capital recovery in § 390.020, the credit shall be calculated pursuant to § 390.021(a)(3).

§ 390.033 Audits.

(a) The accounts of an NPSL lessee or of a contractor of the lessee which are related to NPSL operations shall be subject to audit by DOI or its appointed agent. Where possible, the auditor for DOI shall coordinate audit efforts with other nonoperators, if any. DOE shall have the right to inititate an audit any time within thirty-six months of the due date of the monthly statement that is to be audited or the date that the statement was mailed, whichever is later, provided, however, the audits may not be conducted any more frequently than once every year except upon a showing of fraud or willful misrepresentation.

(b)(1) When nonoperators of an NPSL lease call an audit in accordance with the terms of their operating agreement, the Director shall be notified of the audit call in the same manner as the operator is notified. DOI may elect to send an auditor with the audit team specified by the nonoperators in lieu of calling for a separate audit by DOI.

(2) If DOI determines to call for an audit, DOI shall notify the lessee of its audit call and set a time and place for the audit. Such a notice shall be sent at least thirty days before the suggested time for the audit to allow the nonoperators to join in DOI's audit in lieu of calling for their own audit. The place for the audit will normally be the place where the lessee maintains its records pertaining to the NPSL lease. The lessee shall send copies of the notice to the nonoperators on the lease. The lessee shall use reasonable effort to notify all nonoperators, but failure to include one or more nonoperators in the notification shall not void the notice.

(3) When DOI calls for an audit, DOI may suggest the date and time when the audit may commence. The estimated duration of the audit may be mentioned to the lessee as well as to the other nonoperators who may elect to supply and auditor for their own audit purposes. The lessee's office where the audit will be held may be named or, if not known, inquired about. If a visit to a field plant or field office is contemplated by the government auditor, such a field trip may be mentioned. If DOI expresses a desire to review a period on which the thirty-six month time limitation has expired, it is the lessee's prerogative to allow the review or to request that DOI adhere to the time limitation specified in these regulations.

(c)(1) Exceptions to the accounting by the lessee, whether in favor of the government or the lessee, shall be noted in a report to the lessee. The lessee shall have 60 days from the mailing of a notice of exception to agree to the adjustments proposed by the DOI auditor or to object to the proposed adjustments. If the lessee accepts the proposed adjustments, the adjustment shall be booked in the month in which the lessee agrees to the adjustment, except where such adjustment would have resulted in a change in any net profit share payment due the United States. In such a case, there shall be a redetermination of the NPSL capital account pursuant to § 390.034.

(2) If the lessee disagrees with the adjustment, the lessee shall have the right to appeal the adjustment to the Director.

(d) Upon receipt of an agreement by the government auditor that there are no required audit adjustments, upon final determination with respect to any audit adjustment proposed by the government auditor, or upon the lapse of thirty-six months from the due date or date of mailing

of the statement of account on an NPSL lease, whichever comes later, the books shall be closed for audit adjustment purposes, except upon a showing of fraud or willful misrepresentation.

(e) Records required to be kept under § 390.030(a) shall be made available for inspection by any authorized agent of DOI at any time during normal business hours upon the request of the Director or other authorized official.

§ 390.034 Redetermination and appeals.

(a) If, as a result of an inspection of records or an audit under § 390.033, the Director determines that there is an error in the NPSL capital account or an error in calculating the net profit share payment, whether in favor of the government or the lessee, the Director shall redetermine the net profit share base and recalculate the net profit share payment due the United States and notify the lessee of the recalculation.

(b) The lessee shall pay any additional amount of net profit share payment owed plus interest, compounded monthly, from the date that the payment was due until the date it is actually paid. Interest shall be calculated at the prevailing rate or rates as published in the Bulletin to the Department of the Treasury Fiscal Requirements Manual, in effect for the period or periods over which the payment is owed.

(c) If the recalculated profit share payment is less than the amount paid the United States, the lessee shall apply such overpayment to the next profit share payment.

(d) Within 30 days after receiving notice of the recalculation as provided in paragraph (a) of this section, the lessee may appeal the decision of the Director in accordance with the appeals provision of 30 CFR Part 290.

E. 10 CFR 391, Acquisition and Disposition of Federal Royalty Interests Taken in Kind, 45 FR 9530, February 12, 1980. This final rulemaking is issued pursuant to the authority contained in section 302(b)(5) of the Department of Energy Organization Act (DOE Act). These regulations supersede the existing Department of the Interior (DOI) regulations on Federal OCS royalty oil disposal, found at 30 CFR Part 225a. These regulations will be effective March 13, 1980.

PART 391--ACQUISITION AND DISPOSITION OF FEDERAL ROYALTY INTERESTS TAKEN IN KIND

Subpart A--General Provisions

AUTHORITY: Act of August 7, 1953, ch. 345, secs. 5, 6 and 8, 67 Stat. 464, 465, 468 (43 U.S.C. 1334, 1335 and 1337), as amended by secs. 204, 205 and 208, Pub. L. 95-372, 92 Stat. 636-640, 640-646, 666-668; secs. 302, 303 and 644, Pub. L. 95-91, 91 Stat. 578-599, 579-580, 599 (42 U.S.C. 7152, 7153, and 7254); E.O. 12009, 42 FR 46267.

Subpart A--General Provisions

§ 391.001 Purpose and authority.

The regulations in this Part 391 specify the procedures, terms, and conditions for the acquisition and disposition of Federal royalty interests taken in kind and are issued pursuant to section 302(b)(5) of the DOE Act.

§ 391.002 Definitions.

For purposes of this Part 391--

"Notice of Availability of Royalty Oil" means a notice published in the Federal Register by DOI to advise interested parties that royalty oil is being made available for purchase by qualified small refiners or purchasers and the approximate volume of oil which may be available.

"Operator" means the owner of operating rights or the designee of such parties who own the operating rights including the lessee, who performs the necessary functions relating to oil and gas production.

"Refinery capacity" means actual certified refining capacity on a barrel per calendar day basis, as determined by the Economic Regulatory Administration of DOE.

Subpart B--Disposition of Outer Continental Shelf Royalty Oil

§ 391.101 Purpose and scope.

The regulations in this Subpart B establish the policy and procedures for the disposition of royalty oil taken in kind from Federal OCS oil and gas leases issued pursuant to OCSLA.

§ 391.102 Definitions.

For purposes of this Subpart B:

"Allotment" means the discrete quantity of royalty oil to be sold to a purchaser. The quantity of oil in an allotment shall be determined by DOI and shall be contained in the "Notice of Availability of Royalty Oil."

"Fair market value" means the value of oil determined by DOI (1) computed at a unit price equivalent to the average unit price at which such oil was sold pursuant to a lease during the period for which any royalty or net profit share is accrued or reserved to the United States pursuant to such lease, or (2) if there were no such sales, or if DOI finds that there were insufficient number of such sales to equitably determine such value, computed at the average unit price at which oil was sold pursuant to other leases in the same region of the OCS during such period, or (3) if there were no sales of oil from such region during such period, or if DOI finds that there are an insufficient number of such sales to equitably determine such value, at an appropriate price determined by DOI.

"Lessee" means the holder of a Federal OCS oil and gas lease issued under the OCSLA who is authorized to develop and produce oil and gas, including all parties holding such authority by or through the lessee.

"OCS royalty oil" means, for a section 8 lease, that amount of oil that DOI has determined to take in kind in satisfaction of the section 8 lessee's royalty obligation. "OCS royalty oil" means, for a section 6 lease, that amount of oil that the lessee elects and that DOI accepts as payment in satisfaction of the lessee's royalty obligation.

"Point of delivery" means the place at which OCS royalty oil, or the quantity thereof in a commingled stream, is delivered by the lessee to the United States and ownership of the OCS

royalty oil is transferred simultaneously by the United States to the small refiner/purchaser. With respect to: (1) all leases issued after October 1969, the point of delivery shall be a place designated by or acceptable to the designated official. The deliveries normally shall be made immediately downstream from the place of measurement of such oil or of the commingled stream containing such oil, after separation and treating processes; provided, however, that if such measurement is at an offshore location and such oil is commingled after such measurement with other untreated oil and is transported to a treating facility for treating and final measurement, the point of delivery may be immediately downstream of the place of final measurement; and provided further, that the point of delivery may be at any other place which the designated official determines is practical for both the lessee and the purchaser, and which ensures proper safeguards for the environment; and (2) section 8 leases issued prior to October 1969, the point of delivery shall be a place designated by the lessee.

"Purchaser" means any member of the public who complies with § 391.140(b).

"Regulated price" means the highest price (a) at which oil may be sold pursuant to the Emergency Petroleum Allocation Act of 1973 (Pub. L. 93-159, 87 Stat. 628 (15 U.S.C. 751, et seq.)) and any rule or order issued under such Act, or (b) at which Federal oil may be sold under any provision of law or rule or order thereunder which sets a price (or manner for determining a price) for oil.

"Section 6 lease" means an oil and gas lease originally issued by any State and currently maintained in effect pursuant to section 6 of the OCSLA.

"Section 8 lease" means an oil and gas lease issued by the United States pursuant to section 8 of the OCSLA.

"Small refiner" means an owner of an existing refinery or refineries who can demonstrate its qualification as a small business concern under the rules of the Small Business Administration, both at the time of application and at the time of award of the contract to purchase such oil. The combined refinery capacity of a small refiner shall be employed in determining if a small refiner has demonstrated its qualification under the preceding sentence.

§ 391.110 OCS royalty oil allocation.

(a) Determination by the Secretary of the Interior. The Secretary of the Interior, after consultation with the Secretary of Energy, shall make a determination whether small refiners have access to adequate supplies of oil at equitable prices. The determination by the Secretary of the Interior shall be made prior to any offer to sell OCS royalty oil and shall be published in the Federal Register concurrent with or included in the publication of the Notice of Availability of Royalty Oil.

(b) Allocation to small refiners. (1) Upon a determination by the Secretary of the Interior under paragraph (a) of this section that small refiners do not have access to adequate supplies of oil at equitable prices, DOI may offer OCS royalty oil for sale to small refiners. Such oil may be sold only to small refiners upon application filed in accordance with § 391.140 (a). Such oil may only be purchased for processing or use in a small refiner's refinery or refineries and may not be resold in kind.

(2) All sales of royalty oil to small refiners shall be made at not more than the regulated price or, if no regulated price applies, at the fair market value of the oil. A charge for the cost of administration of an amount equal to one-half percent of the sale price shall be levied for each barrel of OCS royalty oil sold to small refiners.

(3) When available OCS royalty oil is insufficient to satisfy the requirements of all small refiners who have made application, the oil shall be allocated among such small refiners by a drawing or on an equitable prorated basis, as determined by the designated official.

(4) No small refiner shall be awarded contracts for volumes of OCS royalty oil that, when added to volumes of other Federal royalty oil purchased by the small refiner under 30 CFR Part 225 or Subpart C of this Part, are in excess of 60 percent of the combined refinery capacity of that small refiner.

(5) Allocations of OCS royalty oil shall be based upon the refinery capacity as certified by ERA at the time of application; provided that, in the case of new or expanded refinery capacity for which no ERA certification exists that is scheduled to come into operation between the date of application and three months prior to the anticipated effective date of the award of contracts as indicated in the Notice of Availability of Royalty Oil, the designated official may base an allocation upon financial and engineering data certified by the small refiner on anticipated capacity and date of operation. Such data must be sufficient to allow the designated official to determine the capacity of the new or expanded refinery. No contract shall be awarded unless, three months prior to the date of contract award, the small refiner provides to the designated official ERA certification confirming such determination of capacity. However, in the case of the sales of royalty oil anticipated to be effective on July 1, 1960, allocations of OCS royalty oil may be based upon such ERA determination of refinery capacity as DOI, by notice in the Federal Register, may decide to accept.

(c) Allotments to purchasers. (1) DOI may sell OCS royalty oil to purchasers only in accordance with any provision of law, or regula-

tions issued in accordance with such provisions, that provide for DOE to allocate, transfer, exchange, or sell oil in amounts or at prices determined by such provision of law or regulations.

(2) Upon a determination by the Secretary of the Interior under paragraph (a) of this section that small refiners do have access to adequate supplies of crude oil at equitable prices, DOI may offer OCS royalty oil for sale to purchasers. Such oil shall be sold only in equal allotments, by competitive bidding, to purchasers in accordance with the regulations contained in this subpart and may not be resold in kind.

(3) All bids submitted by purchasers of OCS royalty oil must be filed in accordance with § 391.140(b). All sales of royalty oil shall be made at the regulated price or, if no regulated price applies, at not less than the fair market value of the oil.

(4) Allotments of OCS royalty oil shall be awarded to purchasers who are the highest bidders.

(5) No purchaser shall receive more than one allotment of the oil offered at each individual OCS royalty oil sale.

(6) When two or more purchasers bid the same price for the offered OCS royalty oil and their bids, by virtue of their amount, make them eligible for allotments, a drawing shall be held to determine which purchasers shall receive allotments if there are more purchasers than allotments.

(7) If a purchaser is selected for receipt of an allotment and if the purchaser's oil supply requirements, as stated in the application filed in accordance with § 391.140(b)(3), exceed the allotment of oil, the purchaser shall receive only an amount of oil equal to the allotment of oil.

(8) If a purchaser is selected for receipt of an allotment and if the purchaser's oil supply requirements, as stated in his application filed in accordance with § 391.140(b)(3), are less than the allotment of oil, the purchaser shall receive only that amount of oil requested in the application.

(9) If, after all allotments have been sold, an amount of oil remains that is determined by DOI to be large enough for sale, the excess oil shall be made available for sale as another allotment or allotments at that time. Such allotments may be used to increase the allotments previously made.

(10) A charge for the cost of administration of an amount equal to one-half percent of the sales price as provided for in paragraph 3 of this section shall be levied for each barrel of royalty oil sold to purchasers.

(d) Allocation or allotments from section 6 leases and certain section 8 leases. OCS royalty oil produced under a section 6 lease may be made available for sale only when the lessee elects and DOI accepts the royalty oil as payment in satisfaction of the lessee's royalty obligation. OCS royalty oil produced from either section 6 or section 8 leases that are in dispute between the United States and a State as to ownership may be made available for sale only with the concurrence of that State, and evidence of such concurrence shall be furnished by the small refiner/purchaser applicant at such time as may be specified by the designated official.

§ 391.120 Reimbursement to lessee for transportation.

(a) When the point of delivery for OCS royalty oil produced under a section 8 lease is to be other than on or immediately adjacent to the leased area from which the oil is produced, the small refiner/purchaser shall promptly reimburse the lessee for the cost of transporting the oil to the point of delivery. Such reimbursement shall be monthly or at such other interval as may be determined by the designated official.

(b) The cost of transportation shall be approved by the designated official and may be deducted from the value of the oil at the point of delivery in calculating payments to be made to the United States. The United States guarantees payments to the lessee for such cost of transportation.

§ 390.130 Exchange agreement.

(a) Notwithstanding that OCS royalty oil purchased by a small refiner/purchaser cannot be resold, a small refiner/purchaser may enter into an agreement providing for the exchange of OCS royalty oil purchased for other oil on an equivalent volume of value basis. When a small refiner/purchaser anticipates entering into an exchange agreement for any of the OCS royalty oil that it may purchase, complete information regarding such agreement shall be included with the application to purchase OCS royalty oil, unless a later date for submission of such information is specified by the designated official.

(b) Exchange of OCS royalty oil shall not be authorized unless the agreement has been approved by DOI and shall become effective only upon such approval.

§ 391.140 Application; contents.

(a) Small refiner applications. To apply for the purchase of OCS royalty oil offered for sale to small refiners, an applicant must file an application during the application period (as specified in the Notice of Availability of Royalty Oil) with the designated official of the Area or region in which the oil is produced. Such application shall be filed in triplicate and shall include:

(1) Name and address of the applicant and location of its refinery or refineries, disclosure of the applicant's affiliation or association with any other refiner of oil or any other business entity if such relationship exists, and a statement of the reasons which are the bases of the applicant's belief that it qualifies as a small business concern under the rules of the Small Business Administration. The application should also include a self certification by the chief executive officer of the small refiner, or his/her designee, that the refiner is a small business concern in accordance with the rules and regulations of the Small Business Administration;

(2) Certified capacity of the applicant's refinery or refineries in crude throughput of barrels of oil per calendar day, as determined by the Economic Regulatory Administration of DOE, the amount, source and grade of all oil currently available to the applicant from the applicant's own production or by purchase, including any outstanding OCS or onshore royalty oil contracts at the time of application, and in the case of idle facilities or those under construction, the onstream date;

(3) In the case of new or expanded refinery capacity for which no ERA certification exists that is scheduled to come into operation between the date of application and three months prior to the anticipated effective date of the award of contracts as indicated in the Notice of Availability of Royalty Oil, financial and engineering data certified by the small refiner on anticipated capacity and date of operation; such data must be sufficient to allow the designated official to determine refinery capacity;

(4) Minimum amount and grade of additional oil required to meet the applicant's refining capacity and the field or fields that the applicant believes offer a potential source of OCS royalty oil supply;

(5) Tabulation for the last 12 months of refinery operation of the amount and grade of oil refined by the applicant each month and the kind and amount of the principal finished products.

(b) Purchaser applications. To receive OCS royalty oil that is for sale to the public, a purchaser applicant shall file an application during the application period (as indicated in the Notice of Availability of Royalty Oil) with the designated official of the Area or Region in which the oil is produced. Such application shall be filed in triplicate and shall include:

(1) Name and address of the applicant;

(2) Amount of the applicant's bid per barrel per grade of oil (such bid shall not exceed the ceiling price of oil as prescribed by DOE in Part 212 of this chapter); and

(3) Number of barrels and the grade of oil that the applicant desires to purchase.

§ 391.141 Action by the designated official.

(a) The designated official shall examine each application filed and, as appropriate, shall request additional information if the information included in the submitted application is inadequate or unsatisfactory. If an application is received after the close of the application period (as indicated in the Notice of Availability of Royalty Oil), the application shall be automatically rejected. If additional information is requested by the designated official, it must be received in the office of the designated official by the time specified by the designated official or the application shall be automatically rejected.

(b) After the close of the application period and the receipt of any additional requested information, the designated official shall furnish a report to the Director who will make appropriate recommendations to the Secretary of the Interior.

§ 391.142 Action by DOI.

After determinations are made to take OCS royalty oil in kind, the Secretary of the Interior shall make the determination specified in § 391.110(a). Upon publication of such determination in the Federal Register, such OCS royalty oil shall be offered for sale. DOI, by the publication of a Notice of Availability of Royalty Oil in the Federal Register, shall specify the manner in which the sale is to be effected, the approximate quantity of royalty oil to be offered, the closing date for the receipt of applications for royalty oil, other general administrative details concerning the application, and the allocation and contract award process for the royalty oil. The Notice of Availability of Royalty Oil shall describe generally the terms upon which the royalty oil contract will be awarded. In addition, the Secretary of the Interior may authorize the Director or other designated official of the USGS to execute on behalf of the United States any contract for the sale of OCS royalty oil, to approve any exchange agreement, and to determine the amount and type of bond or other security to be required from a small refiner/purchaser in accordance with any contract.

§ 391.150 Notices.

(a) The designated official shall notify the section 8 lessees who shall be required to provide OCS royalty oil to a small refiner/purchaser under a new contract at least 30 days prior to the date on which the first delivery of such oil is to commence.

(b) When delivery of OCS royalty oil is to be suspended or terminated, the designated official shall, if practicable, notify the lessees who are providing such oil at least 30 days

prior to the date on which delivery is to be suspended or terminated.

F. 15 CFR 922, Designation and Management of Marine Sanctuaries, Title 15 CFR, revised as of January 1, 1980.

1. Preamble, 15 CFR 922, Designation and Management of Marine Sanctuaries, 44 FR 44831, July 31, 1979.

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

15 CFR Part 922

Designation and Management of Marine Sanctuaries

AGENCY: National Oceanic and Atmospheric Administration (NOAA), Department of Commerce.

ACTION: Final rule.

SUMMARY: These regulations revise existing regulations which prescribe the procedures for nominating and designating marine sanctuaries, establishing appropriate management systems within designated sanctuaries and enforcing compliance with these management systems. The regulations reflect new approaches and interpretations developed by NOAA during the administration of the program to date.

EFFECTIVE DATE: July 31, 1979.

[44 FR 44837, July 31, 1979]

FOR FURTHER INFORMATION CONTACT:

Joann Chandler, Director, Sanctuary Programs Office, Office of Coastal Zone Management, Page Building 1, 3300 Whitehaven Street, N.W., Washington, D.C. 20235; (202) 634-4236.

SUPPLEMENTARY INFORMATION:

On February 5, 1979, NOAA published proposed revisions to its General Marine Sanctuaries regulations pursuant to Title III of the Marine Protection, Research and Sanctuaries Act of 1972, Pub. L. 92-532, 16 U.S.C. 1431-1434 (the Act). Written comments were requested by April 6, 1979. Comments were received from three members of the House of Representatives, ten Federal agencies, eleven State reviewers, seven industrial groups, fourteen environmental groups, two Regional Fishery Management Councils and three other commentators. These comments have been considered in preparing these regulations.

DISCUSSION OF MAJOR ISSUES AND NOAA RESPONSES

Below is a discussion of the major comments. It is followed by a section-by-section discussion of the additional comments received.

Breadth of Criteria: A number of reviewers felt that the criteria by which an area would be judged eligible for inclusion on a List of Recommended Areas and ultimately for designation as a sanctuary and/or the criteria by which selection of Active Candidates would be made were unclear. Suggestions included qualifying only those areas which are "most unique, rare or distinctive" or "unique" resources. In particular, criterion (b)(2), "a marine ecosystem of exceptional richness . . ." was thought to open up the possibility of vast areas for inclusion. One reviewer thought the present classification scheme (present § 923.10) was preferable.

NOAA Response: NOAA's experience and public reaction have indicated that the present criteria were not helpful. Response to the new criteria was generally favorable. NOAA has rewritten § 922.21 slightly, including § 922.21(b)(2) to provide additional focus and alleviate the concerns expressed. It should be kept in mind that the criteria of § 922.21(b) are necessarily somewhat broad and that the criteria for the selection of Active Candidates will be the basis for narrowing the number of sites actually designated. In addition the boundary section (922.27) has been incorporated into the criteria section to make clearer the intention to concentrate on discrete areas.

Specification of Boundaries: Several reviewers objected to the possibility, inherent in § 922.27, that the boundary of an area being considered for a marine sanctuary could be changed at any time prior to the designation, even following the EIS process, conceivably without consultation.

NOAA Response: NOAA agrees that the regulations as written raised the concern expressed. The regulations have been reorganized to make clear that any changes in boundaries would receive the same examination and consultation as any other changes made during the review process.

Economic Analysis: A number of commentators objected to the omission of the economic value of resources which would be protected by a marine sanctuary designation as a factor to be considered in selecting Active Candidates. These commentators pointed out that the economic consequences of failing to utilize any resources because of sanctuary designation are to be taken into account under § 922.23(a)(6) and rational decisionmaking should balance both factors.

NOAA Response: NOAA agrees with these comments and has added a new § 922.23(a)(7) to add the economic value of the protected resources as a factor to be considered. At the same time, NOAA recognizes that some of the values to be protected under the Act are not easily quantifiable economically and the in-

ability to assign a clear economic value to the resources of an area should not disqualify it as a sanctuary candidate.

Treatment of Esthetics: Five reviewers felt that the esthetic value of an area was not given the proper emphasis in the consideration of that area for possible designation as a marine sanctuary. Section 922.21 did not list the esthetic value of an area alone as one of the resource values making it eligible for placement on the List of Recommended Areas and thus ultimately for designation as a sanctuary. Section 922.23, however, did list the esthetic value of the area as one of the factors to be considered in selecting an area as an Active Candidate once it has been placed on the List of Recommended Areas. Two commentators felt that esthetics alone should qualify an area for listing and ultimately designation and should therefore be included as a separate criteria under § 922.21. One reviewer felt that the esthetic quality of an area was "too vague" to be considered even in the selection of Active Candidates. Two other commentators essentially agreed with NOAA's position that the esthetic quality of an area should be considered, but should not be the sole basis for a sanctuary. They requested additional clarification that esthetics not be the sole basis.

NOAA Response: NOAA believes that the Act provides discretion in treating an area whose sole value is esthetic and that it is highly unlikely that in practice a situation will ever arise where esthetic value will not be combined with one or more of the criteria listed in § 922.21, e.g., recreational use or distinctive or fragile ecological features which will qualify the area for initial listing, and the esthetic value will be one of the factors in considering the priority of the area for actual designation. Consequently, NOAA has not altered the basic treatment of esthetics.

Designation Modification: A number of reviewers suggested that the provisions of § 922. 26 (b) requiring the completion of a full designation procedure to modify a designation could prove burdensome and prevent adequate response to emergency situations.

NOAA Response: NOAA agrees that a certain degree of flexibility to deal with emergency situations is necessary but feels that the more appropriate method is to provide for limited emergency regulation in the Designation document to ensure through the amendment procedure including agency consultation and public review and participation, appropriate review prior to modifying the Designation itself. A provision for emergency regulation has been proposed in the Flower Gardens Marine Sanctuary Designation Document and a new § 922.26(d) has been added to these regulations expressly recognizing such an emergency provision.

SECTION-BY-SECTION ANALYSIS

(a) Section 922.1--Policy.--(1) One commentator suggested that the language is too broad and could include species whose management is primarily the responsibility of the Regional Fishery Management Councils under the Fishery Conservation and Management Act of 1976 (FCMA).

NOAA Response: Both commercial and recreationally valuable species of fish and their habitats are among the resources which a sanctuary could be designed to protect, and activities affecting such species could become subject to control in a designated sanctuary. The Designation document described in § 922.26(b) provides the mechanism for ensuring for each sanctuary that only appropriate activities are regulated and that other activities are excluded from regulation. There is no suggestion in § 922.1 that regulation will include fishing activities or interfere with the management responsibility of the councils.

(2) One reviewer suggested that "minimum regulation necessary to protect legitimate environmental interests" be listed as a major goal of the program.

NOAA Response: Section 922.23 states that the existence of adequate regulatory authority to protect the resources is a criterion for the selection of Active Candidates (see comment (g)(5) below). Furthermore, under the statute only "reasonable and necessary" regulations may be imposed in any sanctuary.

(3) One commentator suggested that some mention of the distinction between the marine and estuarine sanctuary programs be made.

NOAA Response: Section 922.1(d) has been rewritten to describe briefly the estuarine program and cross-reference its regulations.

(4) Three commentators requested additional clarification of the extent to which compatible activities are to be allowed in a sanctuary. One commentator suggested that § 922.1(c) specifically state that "compatible, multiple human use" should be allowed; another suggested that § 922.1(c) specify that activities which "can be made compatible" with the sanctuary be specifically allowed; the third appears to suggest that no human activity be allowed.

NOAA Response: NOAA feels that the formulation of § 922.1(c) clearly provides that compatible activities may take place in a sanctuary and this adequately responds to the concerns of the first two comments. It does not agree with the third commentator that no human activities should be allowed. NOAA's interpretation is supported by the legislative history of the Act.

(5) Two commentators found that § 922.1 (a) and (b) were "somewhat contradictory."

NOAA Response: Section 922.1(b) establishes a "primary emphasis" for the program within the broader purposes described in § 922.1(a). No inconsistency results.

(6) One commentator requested clarification of the distinction between "natural" and "biological" resources. A second commentator suggested that "natural" should read "physical."

NOAA Response: Natural resources includes physical resources. NOAA prefers the somewhat broader term.

(7) One commentator suggested that the purposes should include preservation and restoration for research purposes.

NOAA Response: The significance of an area for research purposes is listed as a criterion for the selection of Active Candidates under § 922.23. NOAA feels this provision sufficiently emphasizes the importance of research, which is not among the values specifically listed in the Act.

(8) Two commentators objected to using cumulative impacts to determine whether or not activities will be allowed in a sanctuary.

NOAA Response: NOAA feels that cumulative impacts can be as significant to the destruction of resources as other impacts and assessing these impacts with respect to certain activities is important. It may be necessary to restrict or ban certain activities to control impacts including cumulative impacts.

(9) One commentator suggested language redrafting § 922.1(a) to clarify the reason for identifying distinctive areas.

NOAA Response: NOAA has redrafted this section as suggested.

(10) One commentator suggested clarification as to who determines whether a use is detrimental.

NOAA Response: The regulations as a whole set forth the procedures for making this determination, which procedures include review of the initial submission, consultations with other Federal agencies, State and local governments and interested parties, and the full EIS procedure.

(11) Two commentators suggested specifying additional programs closely related to marine sanctuaries.

NOAA Response: NOAA has added the programs suggested.

(12) One commentator questioned the phrase, "Congressional design."

NOAA Response: This phrase has been deleted.

(b) Section 922.2—Definitions.--(1) One commentator suggested that terms such as "exceptional richness," "sufficient" and "degradation," be more specifically defined.

NOAA Response: This comment relates essentially to the breadth of the criteria and is analyzed in connection with §§ 922.21 and 922.23.

(2) One commentator questioned whether the definition of "ocean waters" in section 922.2(e) excluded from consideration marine sanctuary sites in estuarine areas lying inland of the baselines from which the territorial sea is measured.

NOAA Response: Exclusion of such areas was unintentional. This definition appears to be unnecessary and has been deleted.

(3) One commentator requested that the area of the Great Lakes eligible for consideration for marine sanctuaries be defined.

NOAA Response: NOAA has included the definition of the Great Lakes contained in the Coastal Zone Management Act.

(4) One commentator objected to the exclusion of the Trust Territories of the Pacific Islands from the definition of "United States" in § 922.2(d).

NOAA Response: This omission was inadvertent and has been corrected.

(c) Section 922.10--Effect of Marine Sanctuary Designation.-- One commentator felt that NOAA should specify the manner in which recognized principles of international law would be applied where sanctuaries include areas outside the territorial sea.

NOAA Response: Following consultation with the State Department, NOAA has determined that such application must be made on a case-by-case basis to ensure conformance with the evolving principles involved.

(d) Section 922.20—Submission of Recommendations.--(1) One commentator suggested that the format for submission should include a description of past uses as well as present and prospective uses.

NOAA Response: NOAA has incorporated this suggestion in the format.

(2) One commentator suggested that the regulations should establish a more affirmative role for NOAA rather than an implicitly passive/reactive role.

NOAA Response: Based on past experience, NOAA anticipates that for the most part potential sites will be brought to NOAA's attention initially by interested persons outside the agency. NOAA has actively solicited this help and relies upon the expertise and experience provided. NOAA on its own could propose an appropriate area for inclusion on the list and § 922.20(a) has been rewritten to make this possibility explicit.

(3) One commentator requested that a copy of any submission be forwarded to the State or States most affected upon receipt; a second commentator suggested that notification be given to the affected local and State agencies and other interested parties.

NOAA Response: A major purpose of including an area in the List of Recommended Areas is to notify all interested persons at the appropriate stage that the area has at least some potential for sanctuary status and earlier notification is unnecessarily burdensome. However, a new § 922.25(a) has been added to provide that, in States with coastal management plans approved under Section 306 of the Coastal Zone Management Act of 1972, as amended, the designated Coastal Zone Management agency will be notified upon

receipt of a recommendation.

(4) One commentator pointed out that the format of § 923.20 should require an explanation of why a particular area should be designated a sanctuary.

NOAA Response: The range of information called for, particularly under the heading "Management," should allow initial analysis of this issue. It is not reasonable to request more specificity from the public prior to the consultation and review process.

(5) One commentator suggested the elimination of the format requirements of § 922.20 (b), allowing the public to submit recommendations essentially in any form, and allowing a 30-day period for NOAA to request additional information.

NOAA Response: NOAA feels that use of the format suggested will provide more timely receipt of necessary information. Additional information can be requested either from the nominator, from outside sources, or from within NOAA itself, and any failure to submit the information suggested can be corrected.

(6) One commentator pointed out that it might be difficult for a recommender to assess the effects of sanctuary regulations.

NOAA Response: NOAA has inserted the word "recommended" in this section of the format to indicate that such assessment should simply be the recommender's suggestion as to what needs to be regulated.

(e) Section 922.21--Analysis of Recommendations.--(1) Three commentators suggested that migration routes and staging areas be added to the life cycle activities described in § 922. 21(b)(3).

NOAA Response: NOAA agrees and has incorporated this suggestion.

(2) Two commentators objected to the inclusion of "rare to the waters to which the Act applies" as a criterion.

NOAA Response: NOAA feels that an obligation exists to consider the necessity of protecting resources which are rare in U.S. waters and, therefore, such areas should be listed. NOAA expects that sites of little overall value will be screened out as Active Candidates are selected.

(3) One commentator suggested deleting historical or cultural remains as criteria for eligibility; a second commentator suggested that these resources might be given less weight than those involving biological resources.

NOAA Response: NOAA feels historical and cultural remains such as the wreck of the U.S.S. Monitor are the subject of strong public interest and are appropriate resources for protection. The program does place "primary emphasis" on physical and biological resources (See § 922.1(b)).

(4) Two commentators objected to criterion (b)(4), "intensive recreational use growing out of * * * distinctive marine characteristics" as being too restrictive. One commentator felt the criterion conflicted somewhat with the purposes in § 922.1.

NOAA Response: NOAA has rewritten § 922.1 in line with the changes suggested by the commentators and does not feel any conflict exits.

(5) Two commentators felt that the criteria of § 922.21(b) underrated the importance of habitat and ecosystem protection.

NOAA Response: The criteria of § 922.21(b) have been rewritten slightly, in part to emphasize such protection.

(6) Two commentators felt that NOAA should specify the reasons for rejecting any recommended site for its List of Recommended Areas and should provide an appeal mechanism to the recommender.

NOAA Response: NOAA agrees with specifying the reasons for rejection but disagrees that an appeal mechanism is appropriate. Any site may be resubmitted for consideration with additional information. Section 922.21(a) has been rewritten to require that the reasons for rejection be specified and a new § 922.21(e) added to provide explicitly for resubmission.

(7) One commentator felt that alternative boundaries and management schemes should be developed prior to publication on the List of Recommended Areas.

NOAA Response: The commentator is placing too much significance of the inclusion on the List of Recommended Areas. Such analysis is premature and beyond the resources of the program. NOAA will develop this information during the review of sites selected as Active Candidates.

(8) One commentator suggested that the words "commercial fishing" be added after "recreational use" in § 922.21(b)(4) to reflect NOAA's responsibilities under the FCMA.

NOAA Response: NOAA feels that fishery management responsibility has been assigned to the National Marine Fisheries Service (NMFS) and the Regional Fishery Councils and, does not anticipate designating sanctuaries solely for fishery management purposes. Certain sanctuaries will include commercially valuable species in which case NOAA's role will involve coordination with the relevant councils. For example, the purpose of designating a sanctuary may include protection of the habitat of a commercially valuable species and sanctuary regulations may restrict certain fishing techniques to protect other marine resources, e.g. trawling to protect coral reefs.

(f) Section 922.22--Effect of Placement on the List.--(1) Five commentators requested clarification as to the effect of the placement of a recommended site on the List of Recommended Areas. Two commentators suggested that the effect of listing an area as an Active Candidate be included in this section.

NOAA Response: The section has been rewrit-

ten to emphasize that the List of Recommended Areas is primarily for informational purposes and to indicate that Active Candidates would normally be mentioned in an Environmental Impact Statement (EIS) prepared by any agency analyzing impacts of a proposed action in the area.

(g) Section 922.23--Selection of Active Candidates.--(1) Three commentators objected that the criteria for selection of Active Candidates was too broad. In particular, two objected to the test of "significance" in § 922.23(a).

NOAA Response: The issues raised are essentially the same as those raised in connection with the criteria of § 922.21 and are discussed under major issues above. NOAA feels that these criteria, when read in conjunction with the criteria of § 922.21, as rewritten, are as specific as possible.

(2) Four commentators suggested that time periods be established for the consideration of Active Candidates. One commentator was concerned about the time period prior to selection as an Active Candidate and suggested a 120 day period to ensure periodic review. The other commentators were concerned about the length of time that a candidate could remain upon the Active Candidates List without designation. No specific time limit was suggested.

NOAA Response: NOAA feels that first commentator overestimates the weight to be given to selection of a site for the List of Recommended Areas, and that no time limit should be established within which an area on the recommended list must become an Active Candidate in light of the large number of Recommended Areas anticipated. Section 922.24 does establish time limits for the review of Active Candidates leading up to the decision to prepare a Draft Environmental Impact Statement (DEIS). However, no time limits for the completion of the EIS process are established. Since NOAA will proceed as quickly as possible with publication of the DEIS, and since Council on Environmental Quality (CEQ) regulations provide a detailed time sequence for DEIS review, no additional deadlines seem necessary.

(3) One commentator suggested that "the significance of area to the development of any energy facility necessary to the National interest" be added as a factor to be considered in the selection of Active Candidates.

NOAA Response: NOAA feels that this factor is taken into account by subsection (a)(6) requiring consideration of "the economic significance to the Nation of such additional resources and uses."

(4) One commentator suggested that the highest priority be given to areas believed to be important habitats for rare, endangered or threatened species.

NOAA Response: Habitat protection is emphasized already (see comment (e)(5) particularly for rare or endangered species--§ 922.21(b)(1)(a)). The factors taken into account in the selection of Active Candidates: e.g., the severity and imminence of threats, are also valid considerations.

(5) One commentator suggested that the availability of other regulatory authorities should be a separate, principal criterion for selecting Active Candidates to emphasize its significance (See also comment (a)(2).) Another reviewer objected to considering this criterion at all.

NOAA Response: NOAA feels that on balance the emphasis placed on existing regulations by § 922.23(a)(2) is the proper one.

(6) One commentator objected to establishing the value of an area in complementing other areas as a criterion for the selection of Active Candidates.

NOAA Response: NOAA believes that this is a valid consideration and will maximize the importance of the marine sanctuary program in relation to other government programs.

(7) One commentator suggested that priorities be set forth in terms of the significance of ecosystems at global, national and State levels.

NOAA Response: NOAA agrees with the general concept but does not feel that it is useful to specify this particular hierarchy in the regulations. The precise degree of significance could be debated in scientific communities and involving NOAA in these debates does not appear productive.

(8) One reviewer objected to examining cumulative impacts in determining the severity of potential threats to the resources.

NOAA Response: NOAA disagrees. Instances may exist where individual activities could not be said to pose a severe threat to the resources of an area, but the total number of such activities anticipated would pose such a threat.

(9) Two commentators suggested that specific justification for treating an area as significant to research be provided.

NOAA Response: There does not appear to be any need to require special justification for the importance of research.

(10) One reviewer requested further clarification of what constitutes adequate means available to support full review.

NOAA Response: This means simply adequate budget and personnel in the relevant NOAA program offices.

(11) Three commentators objected to the description of consultation set forth in § 922.23(b). Two claimed it appeared to make the consultations discretionary. The third suggested rephrasing to provide a more positive connotation.

NOAA Response: NOAA disagrees that there is any ambiguity as to whether the Assistant Administrator must consult with the named parties.

The rephrasing suggested has been adopted.

(12) One commentator has suggested announcing the selection of an Active Candidate in local papers.

NOAA Response: NOAA will issue a press release for local area newspapers which should assure adequate publicity.

(h) Section 922.24--Review of Active Candidates.--(1) Three commentators suggested that this section specify that the workshops to discuss Active Candidates be held in the area or areas most significantly affected by the proposed designation.

NOAA Response: NOAA concurs. Section 922.24 (a) has been rewritten to so provide.

(2) Two reviewers felt that alternative boundaries, management measures and other fairly detailed information must be provided prior to the holding of public workshops.

NOAA Response: NOAA appreciates the importance of holding informed public meetings, but feels these commentators tend to confuse the function of the workshop with the function of the public hearing to be held on the Draft Environment Impact Statement later in the process. In many cases, the public workshop will aid in the formulation of such options, and the attempt to provide them in advance of this first major public consultation may frustrate effective public involvement. NOAA will supply as much information as possible.

(3) One commentator suggested specifically providing that compensation under NOAA's public participation regulations may be available for the workshops.

NOAA Response: NOAA agrees. New § 922.1(f) states that compensation is available in appropriate circumstances and cross references the public paticipation regulations (15 CFR Part 904).

(4) One commentator suggested that § 922.24 specifically include affected land owners in the workshops.

NOAA Response: NOAA feels that the change is unnecessary since such individuals are clearly covered by "other interested persons."

(5) One commentator suggested that the hearing provided for in § 922.24(c) is at the wrong stage in the process and should be at the beginning of the site selection process.

NOAA Response: NOAA feels that the commentator is placing undue weight upon the selection of a site for the List of Recommended Areas and that it is more appropriate to hold the hearing when full information is available and the regulatory options are apparent. The time of the hearing is in line with the statutory requirement of § 302(e) of the Act. The public workshops at the early stages of evaluating an Active Candidate will answer the commentator's concern.

(6) One commentator suggested amending § 922.24(b) and § 922.26(a) to reflect that an EIS may not be required.

NOAA Response: NOAA intends to use the EIS process for disseminating information any time it proposes a sanctuary whether or not required under the National Environmental Policy Act (NEPA).

(7) One commentator suggested that if, following a public workshop, NOAA determines not to proceed with the DEIS, an announcement stating the reasons for the determination should be placed in the Federal Register.

NOAA Response: NOAA concurs and has amended § 922.24(b) appropriately.

(8) One commentator suggested appointing State and local citizen advisory councils to further the consultation process.

NOAA Response: NOAA agrees that in many cases such bodies may be helpful but does not feel it appropriate to require this in all cases. In addition the Federal Advisory Committee Act restricts NOAA's ability to appoint such committees.

(i) Section 922.25-Coordination with States. --(1) One commentator felt that the proposed regulations are too general in their provision for the necessary coordination procedure, particularly with respect to the preparation of the Designation document and regulations.

NOAA Response: The regulations fully involve the relevant parties in the process of preparation of the Designation and regulations. §§ 922.24(b) and 922.26(a) have been rewritten to clarify this role.

(2) One reviewer objected to the failure of § 922.25(a)(3) to state that sanctuary designations must be consistent with the States' coastal zone management programs.

NOAA Response: NOAA has reworded this section to refer to the necessity for consistency with a State's approved coastal zone management program.

(j) Section 922.26--Designation.--(1) Three commentators complained that the relationship between the Designation and the regulations implementing the Designation was unclear, and particularly that the opportunity for interested persons to participate in the development of the regulations was not clearly established.

NOAA Response: NOAA has rewritten § 922.26 (a) as well as § 922.24(b), Review of Active Candidates, to clarify the relationship and emphasize the public's role in the development of the Designation and regulations particularly at the workshops and through the DEIS process prior to designation.

(2) Three commentators addressed the use of the Designation document as set forth in this section. Two commentators favored the device as a method for avoiding overregulation. A third commentator objected that NOAA should not limit its ability to regulate activities in a sanctuary. Other commentators discussed generally the need to avoid overregulation but did not specifically recognize the Designation

document as a method to accomplish this end.

NOAA Response: NOAA feels that the Designation document in the form described in the regulations is an important and useful mechanism to focus public and agency attention on the need for regulations and the appropriate limits for each regulation.

(3) Three commentators discussed the veto authority given to the Governor of a State whose waters are included in the sanctuary. One favored and one opposed this authority. The third felt that § 922.26(d) allowed designation, despite a Governor's objection.

NOAA Response: The Governor's authority is statutory. See § 302(b) of the Act. NOAA disagrees that under either the statute or § 922.26(d) it can designate a sanctuary in State waters despite the Governor's objection.

(4) Two commentators suggested specifying a time limit for the Governor's certification.

NOAA Response: Section 302(b) of the Act gives a governor 60 days to certify unacceptability. This limit has been added for clarity.

(5) Two commentators suggested that NOAA utilize some form of "emergency designation." One commentator suggested promulgating some form of regulations imposing, in essence, a moratorium on degrading activities pending designation. A second commentator favored expediting the placement of a site on the Active Candidates List (i.e. within 30 days of receipt of the recommendation).

NOAA Response: Under the Act, NOAA is empowered to control activities in an area only after its designation as a sanctuary. With respect to expedited processing, NOAA can expedite its procedures for any recommended site so long as the required consultations and evaluations took place.

(6) One commentator thought the Designation should be more specific as to the extent to which activities in a sanctuary may be regulated.

NOAA Response: Certain Designations may provide such specificity, but NOAA disagrees that it is desirable or even possible in all cases.

(7) One commentator suggested it might be useful to describe in a Designation other regulatory programs applicable to the sanctuary area.

NOAA Response: NOAA feels that it is more appropriate to describe such regulatory programs in the EIS.

(8) One commentator suggested that the Designation should be the subject of a separate subpart to stress that selection of an Active Candidate does not necessarily lead to designation.

NOAA Response: NOAA feels that a separate section is adequate to provide clarity, and that the concept is stressed throughout.

(9) One commentator suggested rewriting § 222.26(a) to provide explicitly for the receipt of evidence from appropriate parties including citizens of the affected state.

NOAA Response: NOAA feels such addition is superfluous.

(10) Two commentators objected to NOAA's failure to preempt each and every regulatory authority in the area of a designated sanctuary and recommended retaining the requirement that all other authorizations be certified before they are valid.

NOAA Response: NOAA agrees that its authority could preempt other regulatory authorities in the area, but sees advantages in terms of providing clarity to potential users and, generally, of reduced bureaucracy, in not doing so unless necessary.

(11) One commentator suggested that § 922.26 (c) provide explicitly that multiple use be permitted provided it does not cause significant adverse impact.

NOAA Response: This concept is clearly established by § 922.1 and § 922.26 is built on this principle.

(12) One commentator suggested that the concurrence of other affected Federal agencies should be required prior to the promulgation of any regulations.

NOAA Response: NOAA disagrees. Consultation with other Federal agencies is required by statute. Presidential approval of the designation is the statutory mechanism to insure balancing the interests of all Federal agencies. It takes the place of other mechanisms for resolving conflicts such as the mediation provided in the Coastal Zone Management Act.

(13) One commentator suggested formal notice of a designation be provided in the Federal Register.

NOAA Response: NOAA concurs. See new § 922. 26(e).

(k) Section 922.27—Boundaries.—

(1) Seven commentators objected to the provision for altering boundaries and expressed concern about appropriate consultation.

NOAA Response: This section has been consolidated with section 922.21 to address this concern. See also discussion under Major Issues above.

(2) One commentator expressed concern that criteria 922.27(a)(2) was too broad and too open to subjective judgment.

NOAA Response: The determination of what constitutes an adequate buffer zone to protect the resources of a sanctuary is necessarily made on a case-by-case basis. The determination will be made through the full review in the designation process, thus minimizing subjectivity.

(l) Section 922.30—Penalties.—

(1) Two commentators thought this section and § 922.31 should specify the agency responsible for enforcement.

NOAA Response: Different agencies will have enforcement responsibilities. The individual

regulation for each sanctuary is the proper place to specify such responsibility. The Coast Guard will be responsible for enforcement in most sanctuaries and a specific reference to this agency's enforcement programs has been included in section 922.1(e).

(2) One commentator felt the regulations should specifically provide for the delegation of enforcement and administration to State agencies for sanctuaries located off their shores. The commentator believed the existing regulations provided explicitly for such delegation.

NOAA Response: The existing regulations do not provide explicitly for delegation. NOAA agrees that delegation may be appropriate in individual sanctuaries and will provide for it in the regulations governing these sanctuaries.

REVISED REGULATIONS EFFECTIVE IMMEDIATELY

The regulations described above constitute general statements of policy and rules of procedure or practice governing the administration of the marine sanctuary program by NOAA. For the most part, the practices and procedures have evolved under the existing regulations and are being followed currently. Consequently, to delay the effective date for thirty days would simply result in additional confusion, and NOAA hereby finds for good cause, in accordance with 5 U.S.C. 553(d), that such 30 days delay prior to the effective date is unnecessary. The regulations are effective on publication in the Federal Register.

R. L. CARNAHAN,
Deputy Assistant Administrator for Administration

JULY 23, 1979

2. Regulations, 15 CFR 922, Designation and Management of Marine Sanctuaries, Title 15 CFR, revised as of January 1, 1980.

PART 922—MARINE SANCTUARIES

Subpart A—General

AUTHORITY: Title III, Public Law 95-532, as amended; 86 Stat. 1061 (16 U.S.C. 1431-1434).

SOURCE: 44 FR 44837, July 31, 1979, unless otherwise noted.

Subpart A—General

§ 922.1 Policy and Objectives.

(a) The purpose of the marine sanctuaries program is to identify areas in the ocean from the shore to the edge of the continental shelf and in the Great Lakes that are distinctive for their conservation, recreational, ecological or esthetic values, and to preserve and restore such areas by designating them as marine sanctuaries and providing appropriate regulation and management.

(b) The primary emphasis of the program will be the protection of natural and biological resources, and in most cases higher priority will be afforded candidate sites containing these resources.

(c) The presence of actual or potential conflicts among existing or potential human uses of a candidate site is not of itself a basis for designating the site as a marine sanctuary. Human activities will be allowed within a designated sanctuary to the extent that such activities are compatible with the purposes for which the sanctuary was established, based on an evaluation of whether the individual or cumulative impacts of such activities may have a significant adverse effect on the resource value of the sanctuary.

(d) The marine sanctuary program will be fully coordinated with the coastal zone management and estuarine sanctuary programs established under the Coastal Zone Management Act of 1972, as amended 16 U.S.C. 1451 et seq. (The estuarine sanctuary program, 16 U.S.C. 1461, authorizes grants for the acquisition, development or operation of estuarine areas as natural field laboratories. See regulations at 15 CFR Part 921).

(e) The marine sanctuaries program will be conducted also in close cooperation with other related Federal and State programs, including those of the Regional Fishery Management Councils under the Fishery Conservation and Management Act of 1976, as amended, 16 U.S.C. 1801 et seq.; the marine mammal protection and endangered species programs of the National Marine Fisheries Service, under the Marine Mammal Protection Act, as amended, 16 U.S.C. 1361 et seq. and the Endangered Species Act, as amended, 16 U.S.C. 1531 et seq.; leasing programs of the Department of the Interior for the Outer Continental Shelf under the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1331 et seq.; relevant programs of the Department of Energy; and the regulatory and enforcement programs of the United States Coast Guard.

(f) A basic objective of the marine sanctuaries program is to obtain the maximum public participation throughout all the stages that may lead to the designation of a sanctuary. To further this purpose NOAA may make funds available to compensate eligible persons for the costs of participation in certain proceedings in accordance with NOAA regulations at 15 CFR Part 904.

§ 922.2 Definitions.

(a) "Act" means Title III of the Marine Protection, Research and Sanctuaries Act of 1972, as amended, 16 U.S.C. 1431-1434.

(b) "Administrator" means the Administrator of the National Oceanic and Atmospheric Administration, United States Department of Commerce.

(c) "Assistant Administrator" means the Assistant Administrator for Coastal Zone Management, National Oceanic and Atmospheric Administration, United States Department of Commerce, or his designee.

(d) "Continental Shelf" means the Continental Shelf, as defined in the Convention on the

Continental Shelf, 15 U.S.T. 74 (TIAS 5578), which lies adjacent to any of the several states or any territory or possession of the United States, or the Trust Territory of the Pacific Islands.

(e) The "Great Lakes" means the waters within the territorial jurisdiction of the United States consisting of the Great Lakes, their connecting waters, harbors, roadsteads, and estuary-type areas such as bays, shallows, and marshes.

(f) "Person" means any private individual, partnership, corporation, or other entity; or any officer, employee, agent, department, agency or instrumentality of the Federal Government, or any State, local or regional unit of government.

§ 922.10 Effect of marine sanctuary designation.

The designation of a marine sanctuary and the regulations implementing it are binding on any person subject to the jurisdiction of the United States. Designation does not in any case constitute any claim of territorial jurisdiction on the part of the United States, and the regulations implementing it apply to foreign citizens only to the extent consistent with recognized principles of international law or authorized by international agreement.

Subpart B--Initial Review of Areas Recommended as Sanctuaries.

§ 922.20 Submission of recommendations.

(a) Any person (including NOAA employees in their official capacity or otherwise) may recommend a site to be considered for potential designation as a marine sanctuary. Recommendations should be addressed to: Director, Sanctuary Programs Office, Office of Coastal Zone Management, National Oceanic and Atmospheric Administration, 3300 Whitehaven St., N.W., Washington, D.C. 20235.

Further information can be obtained by contacting this office.

(b) Recommendations should be submitted in the following format:

Site recommended
General description of area
Approximate coordinates
Area in square miles
Name of person or organization submitting recommendation
Principal Contact
  Name, Title
  Address
  Telephone number
Detailed description of the feature or features which make the site distinctive (See Sec. 922.21)
Available data on the resources and site
Summary of existing research and other data to support description
  Principal data deficiencies
Description of past, present and prospective uses of site
Impacts of present and prospective uses on site and its distinctive features
Probable effects of marine sanctuary designation and recommended regulations
  Present uses of resources
  Future uses of resources
  Uses of adjacent areas (including those on shore)
Management
  Summary of who should manage area and why
  Summary of activities which must be regulated to ensure protection of distinctive features

(c) The Assistant Administrator may request such additional information as is necessary to make the determination called for by §§ 922.21 and 922.23.

§ 922.21 Analysis of recommendations.

(a) Within 3 months of receiving a recommendation for any site the Assistant Administrator shall review the site in accordance with the criteria of subsection (b) to determine if it should be placed on the List of Recommended Areas. The Assistant Administrator shall promptly notify the recommender in writing of his determination. In the event the site is rejected, the Assistant Administrator shall include a statement of the reasons for the rejection and indicate that the recommendation may be resubmitted with additional information. Notification of the placement of any site on the List will be published in the Federal Register.

(b) To be eligible for placement on the List of Recommended Areas for marine sanctuaries a candidate area shall contain one or more of the following:

(1) Important habitat on which any of the following depend for one or more life cycle activity, including breeding, feeding, rearing young, staging, resting or migrating:

(i) Rare, endangered or threatened species; or

(ii) Species with limited geographic distribution, or

(iii) Species rare in the waters to which the Act applies, or

(iv) Commercially or recreationally valuable marine species.

(2) A marine ecosystem of exceptional productivity indicated by an abundance and variety of marine species at the various tropic levels in the food web.

(3) An area of exceptional recreational opportunity relating to its distinctive marine

characteristics.

(4) Historic or cultural remains of widespread public interest.

(5) Distinctive or fragile ecological or geologic features of exceptional scientific research or educational value.

(c) Sanctuary boundaries should include an area sufficient to provide reasonable assurance that the resource value of the area can be protected against degradation or destruction. The boundary will not include an area greater than that appropriate to protect the resource. The determination of boundaries should consider the following elements, depending on the resource values that justify establishing the sanctuary:

(1) The range and interrelations of key elements of the ecosystem,

(2) The potential for adverse impact from human activities at some distance from where they are conducted, whether as a result of normal operations or foreseeable accidents,

(3) The economic, safety, and other effects of displacing certain human activities to other locations to the extent such displacement is likely to occur,

(4) The feasibility and cost of conducting surveillance and enforcement activities in the area.

(d) Where overlapping or adjacent sites are recommended or where the recommended boundaries of an area appear either excessive or inadequate to protect the identified features, the Assistant Administrator may prepare a combined or revised description for placement on the List of Recommended Areas.

(e) All recommendations submitted prior to the effective date of these regulations will be reviewed in accordance with this section and an initial List of Recommended Areas will be published in the Federal Register within 3 months of such date. Thereafter the List will be updated at least semi-annually and a cumulative List published in the Federal Register.

§ 922.22 Effect of Placement on the List of Recommended Areas or Active Candidates

(a) The List of Recommended Area provides a source of information on sites believed to contain some resource value and may be helpful to Federal agencies and others planning or conducting activities that affect these sites. It is anticipated that, normally, once a site is selected as an Active Candidate, such status will be mentioned in an agency's Environmental Impact Statement (EIS) covering such an activity.

(b) Placement of a site on either List does not establish any regulatory controls, which can be established only after designation in accordance with § 922.26. Listing is a prerequisite for designation as a marine sanctuary but many more sites will be listed than designated and listing does not imply that designation will ever occur.

Subpart C--Selection of Active Candidates and Designation of Sanctuaries

§ 922.23 Selection of Active Candidates.

(a) A site on the List of Recommended Areas will be selected as an Active Candidate for designation as a marine sanctuary on the basis of:

(1) The significance of the resources identified during review for listing under § 922.21 (b);

(2) The extent to which the means are available to the Assistant Administrator to support full review within the time specified in § 922.24; and

(3) The following additional factors:

(i) The severity and imminence of existing or potential threats to the resources including the cumulative effect of various human activities that individually may be insignificant.

(ii) The ability of existing regulatory mechanisms to protect the values of the sanctuary and the likelihood that sufficient effort will be devoted to accomplishing those objectives without creating a sanctuary.

(iii) The significance of the area to research opportunities on a particular type of ecosystem or on marine biological and physical processes.

(iv) The value of the area in complementing other areas of significance to public or private programs with similar objectives, including approved Coastal Zone Management programs.

(v) The esthetic qualities of the area.

(vi) The type and estimated economic value of the natural resources and human uses within the area which may be foregone as a result of marine sanctuary designation, taking into account the economic significance to the nation of such resources and uses and the probable impact on them of regulations designed to achieve the purposes of sanctuary designation.

(vii) The economic benefits to be derived from protecting or enhancing the resources within the sanctuary.

(b) Before selecting a site as an Active Candidate, the Assistant Administrator shall consult on a preliminary basis with relevant Federal agencies, state and local officials including port authorities, Regional Fishery Management Councils and other interested persons including the recommender to determine the nature of potential impacts in the area and to gather additional information as necessary to conduct the review process.

(c) Selection of any site as an Active Candidate for designation shall be announced in the Federal Register and all Active Candidates shall be placed on a separate list published

and updated concurrently with the List of Recommended Areas as provided in § 922.21(e).

(d) Any site for which a Public Workshop as described in § 922.24(a) has been held or for which such a workshop has been scheduled prior to the effective date of these regulations, shall be considered an Active Candidate. These Active Candidates shall be announced in the Federal Register as soon as practicable after the effective date of these regulations, and prerequisites to Active Candidate status will be considered satisfied by inclusion in this announcement.

§ 922.24 Review of active candidates.

(a) Within six months of selection as an Active Candidate as specified in § 922.23, the Assistant Administrator shall conduct one or more Public Workshops in the area or areas most affected to solicit the views of interested persons to aid in determining whether the site should be further considered for Designation and whether any modifications to the recommendation may be appropriate. This workshop shall be before and in addition to the public hearings required under section 302(e) of the Act.

(b) Based on the views obtained at the Public Workshop and other relevant information, the Assistant Administrator shall determine whether the site should continue to be an Active Candidate and shall announce that decision in the Federal Register within 90 days of the last Public Workshop. If the site will not continue to be an Active Candidate, the notice shall specify the reasons. If the site continues to be an Active Candidate, the Assistant Administrator shall prepare a draft Environmental Impact Statement (DEIS), containing a draft Designation document and regulations implementing the Designation in consultation with relevant Federal, State and local officials, Regional Fishery Management Council members and other interested persons. At or about the same time, the Assistant Administrator will publish the proposed Designation and regulations in The Federal Register in accordance with the Administrative Procedure Act.

(c) No less than 30 days after the Environmental Protection Agency (EPA) publishes a Notice of Availability in the Federal Register, the Assistant Administrator shall hold at least one public hearing in the area or areas most affected by the proposed designation in accordance with section 302(e) of the Act to consider the draft Designation, proposed regulations and DEIS.

§ 922.25 Coordination with States.

(a) Following the receipt of any recommendation, the Assistant Administrator shall notify the designated Coastal Zone Management Agency of an affected State or States with an approved Coastal Zone Management Program.

(b) The Assistant Administrator shall make every effort to consult and cooperate with affected States through the entire review and consideration process. In particular the Assistant Administrator shall:

(1) Consult with the relevant State officials prior to selection of an Active Candidate for consideration, pursuant to § 922.23(b),

(2) Ensure that any State agency designated under sections 305 or 306 of the Coastal Zone Management Act of 1972 and any other appropriate State agency is consulted prior to holding any Public Workshop pursuant to § 922.24(a) or public hearing pursuant to § 922.24(c), and

(3) Ensure that such Public Workshops and Public Hearings include consideration of the relationship of a proposed designation to State waters and the consistency of the proposed designation with an approved State Coastal Zone Management Program.

§ 922.26 Designation.

(a) In response to the comments received, including those at the Public Hearing described in § 922.24(c), the Assistant Administrator shall prepare a final environmental impact statement including the Designation and implementing regulations and file it with EPA. After final consultation with all appropriate Federal agencies and Regional Fishery Management Councils, the Secretary shall transmit to the President for approval the proposed Designation prior to making the site a Marine Sanctuary.

(b) The Designation shall specify by its terms the geographic coordinates of the Sanctuary area, its distinctive features that require protection, and the types of activities that may be subject to regulation. The terms of the Designation may be modified only by the same procedures through which the original designation was made.

(c) The regulations shall be consistent with and implement the terms of the Designation and shall set forth the limits of human activities within the sanctuary and procedures for the review and certification of permits, licenses or other authorizations pursuant to other authorities. All amendments to these regulations must remain consistent with the Designation.

(d) Where essential to prevent immediate, serious and irreversible damage to the resources of a sanctuary, activities other than those listed in the Designation may be regulated within the limits of the Act on an emergency basis for an interim period not to exceed 120 days, during which an appropriate amendment of the Designation would be sought.

(e) If, within 60 days of the publication of the Designation as provided in paragraph (e), the Governor of a state whose waters are included in the sanctuary certifies that any terms of

the Designation are unacceptable, such terms and any regulations implementing them shall not become effective for the part of the sanctuary in state waters until the certification is withdrawn. If the Governor so certifies, the Designation may be withdrawn if, in the opinion of the Assistant Administrator, the sanctuary, as modified, no longer achieves the objectives specified in the Act, the regulations, and the Designation.

(f) The Assistant Administrator shall announce the designation of a Sanctuary and publish the designation document and implementing regulations in the Federal Register.

Subpart D—Enforcement

§ 922.30 Penalties.

Any person subject to the jurisdiction of the United States who violates any regulation issued pursuant to the Act shall be liable for a civil penalty of not more than $50,000 for each such violation. Each day of a continuing violation shall constitute a separate violation. No penalty may be assessed under this section until the person charged has been given notice and an opportunity to be heard. Upon failure of the offending party to pay an assessed penalty, the Attorney General, at the request of the Administrator, will commence action in the appropriate District Court of the United States in order to collect the penalty and to seek such other relief as may be appropriate. A vessel used in the violation of a regulation issued pursuant to the Act will be liable in rem for any civil penalty assessed for such violation and may be proceeded against in any District Court of the United States having jurisdiction thereof. Pursuant to section 303(a) of the Act, the District Courts of the United States having jurisdiction to restrain a violation of the regulations issued pursuant to the Act, and to grant such other relief as may be appropriate.

§ 922.31 Notice of violation.

Upon receipt of information that any person has violated any provision of this title, the Administrator shall notify such person in writing of the violation with which charged, and of the right to demand a hearing to be held in accordance with § 922.32. The notice of violation shall inform the person of the procedures for requesting a hearing and may provide that, after a period of 30 days from receipt of the notice, any right to a hearing will be deemed to have been waived.

§ 922.32 Enforcement hearings.

Hearings requested under § 922.31 shall be held not less than 60 days after the request is received. Such hearings shall be on the record before a hearing officer. Parties may be represented by counsel, and shall have the right to submit motions, to present evidence in their own behalf, to cross examine adverse witnesses, to be apprised of all evidence considered by the hearing officer, and, upon payment of appropriate costs, to receive copies of the transcript of the proceedings. The hearing officer shall rule on all evidentiary matters and on all motions, which shall be subject to review pursuant to § 922.33.

§ 922.33 Determinations.

Within 30 days following conclusion of the hearing, the hearing officer shall make findings of facts and recommendations to the Administrator, unless such time limit is extended by the Administrator for good cause. When appropriate, the hearing officer may recommend a penalty, after consideration of the gravity of the violation, prior violations by the person charged, and the demonstrated good faith by such person in attempting to achieve compliance with the provisions of the title and regulations issued pursuant thereto. A copy of the findings and any recommendation of the hearing officer shall be provided to the person charged at the same time they are forwarded to the Administrator. Within 30 days of the date on which the hearing officer's findings and recommendations are forwarded to the Administrator, any party objecting thereto may file written exceptions with the Administrator.

§ 922.34 Final action.

A final order on a proceeding under this part shall be issued by the Administrator no sooner than 30 days following receipt of the findings and recommendations of the hearing officer. A copy of the final order shall be served by registered mail (return receipt requested) on the person charged or his representative.

G. 15 CFR 930, Federal Consistency with Approved Coastal Management Programs, Title 15 CFR, revised as of January 1, 1980.

1. Preamble, 15 CFR 930 Consistency for Department of the Interior Outer Continental Shelf (OCS) Prelease Sale Activities and for Other Federal Activities Directly Affecting the Coastal Zone, 44 FR 37142, June 25, 1979.

DEPARTMENT OF COMMERCE

National Oceanic and Atomospheric Administration

15 CFR Part 930

Consistency for Department of the Interior Outer Continental Shelf (OCS) Prelease Sale Activities and for Other Federal Activities Directly Affecting the Coastal Zone

AGENCY: National Oceanic and Atomospheric Administration, Commerce.

ACTION: Final rule.

SUMMARY: This rule amends existing regulations to provide conformance with the U.S. Justice Department opinion, dated April 20, 1979, which concludes that the Department of the Interior's Outer Continental Shelf (OCS) prelease sale activities which directly affect the coastal zone must be undertaken in a manner consistent, to the maximum extent practicable, with the requirements of approved coastal management programs in accordance with section 307(c)(1) of the Coastal Zone Management Act (CZMA), as amended. The opinion further provides that the phrase "directly affecting" in section 307(c)(1) of the CZMA, which specifically applies to OCS prelease sale activities, should be included in the regulations instead of using alternative language such as "significantly" affecting the coastal zone in terms of "primary," "secondary" and "cumulative" impacts presently in the regulations. The amendments to the regulations also include minor editorial modifications and corrections.

EFFECTIVE DATE: June 25, 1979.

FOR FURTHER INFORMATION CONTACT:

Michael E. Shapiro, Policy Program Evaluation, Office of Coastal Zone Management, (202) 634-4245, NOAA, Page Building 1, 2001 Wisconsin Avenue, N.W., Washington, D.C. 20235.

SUPPLEMENTARY INFORMATION:

(A) Consistency for OCS Prelease Sale Activities

On April 20, 1979, the U.S. Department of Justice issued an opinion which concluded that neither the CZMA Amendments of 1976 nor the OCS Lands Act Amendments of 1978 repealed the application of section 307(c)(1) consistency to the Department of the Interior's OCS prelease sale activities. The opinion jointly was requested by the Commerce and Interior Departments because they were unable to agree on whether section 307(c)(1) applied to OCS preleasing activities (see 42 FR 43591-92, August 29, 1977, and 43 FR 10512, March 13, 1978.) The Justice Department opinion supports the position taken by the Department of Commerce on this point.

Department of the Interior (DOI) OCS prelease sale activities include the determination of tracts to be offered for sale and choice of lease stipulations. In cases where these types of actions directly affect the coastal zones of States with approved coastal programs, DOI must ensure that the actions are conducted in a manner consistent, to the maximum extent practicable, with coastal program provisions. This requirement is now embodied in a Comment under § 930.71 of the regulations.

In reaching its decision, the Justice Department took notice of the legislative history of the OCS Lands Act Amendments where Congress indicated that:

"Under the Coastal Zone Management Act of 1972, as amended in 1976 (16 U.S.C. 1451 et seq.), certain OCS activities including lease sales and approval of development and production plans must comply with "consistency" requirements as to coastal management plans approved by the Secretary of Commerce. Except for specific changes made by Titles IV and V of the (OCS Lands Act) Amendments, nothing in this Act is intended to amend, modify or repeal any provision of the Coastal Zone Management Act. Specifically, nothing is intended to alter procedures under the Act for consistency once a State has an approved Coastal Zone Management Plan." (H. Report 95-590, p. 153, fn. 52.)

The Justice Department also pointed out that the application of section 307(c)(1) consistency to DOI's OCS prelease sale activities complements the section 307(c)(3)(B) consistency requirement applicable to lessee OCS plans because:

"It is well possible that some of the preleasing activities of the Secretary of the Interior will give rise to consistency problems which cannot be reviewed at all under the paragraph (B) procedure, or for which such review comes too late."

Accordingly, section 307(c)(1) of the CZMA applies to DOI's OCS prelease sale activities directly affecting the coastal zone. As

indicated in Subpart C of the regulations, the "directly affecting" threshold test is normally to be applied on a case-by-case basis, depending on the factual character of the Federal activity under review. Implementation of this requirement at the OCS prelease sale stage should lead to minimization of adverse coastal environmental and socioeconomic impacts, thereby reducing conflicts with affected States and avoiding delay in the exploitation of offshore energy resources. The Office of Coastal Zone Management will be available to work closely with DOI and affected coastal States to ensure expeditious implementation and coordination for this requirement.

(B) The phrase "Directly Affecting" the Coastal Zone

In the same opinion, the Justice Department took issue with the Department of Commerce regulations that define the section 307(c)(1) phrase "directly affecting" the coastal zone to mean "significantly" affecting the coastal zone in terms of "primary," "secondary" and "cumulative" impacts (see 15 CFR 930.21, 43 FR 10518-19, March 13, 1978). The Justice Department determined that the plain language of the statute should control and declared that the issue —under what circumstances a given Federal activity "directly affected" a State's coastal zone--is essentially one of fact. The Justice Department concluded that Congress explicitly expressed an intent in the CZMA to apply different standards to the various consistency provisions and, therefore, no justification for eliminating these statutory distinctions exists.

In response to this opinion, NOAA is deleting the definition "significantly affecting the coastal zone" in section 930.21, and will use, without definition, the term "directly affecting" in Subpart C of the regulations (Consistency for Federal Activities). Similarly, the "significant" effect test will no longer apply to Federal actions covered by Subpart D (Consistency for Activities requiring a Federal License or Permit). Subpart E (Consistency for Outer Continental Shelf Exploration, Development and Production Activities) and Subpart F (Consistency for Federal Assistance to State and Local Governments). In Subparts D, E and F, the term "affecting the coastal zone" will be used, again without definition. This is the common statutory threshold test used in sections 307(c)(3)(a), 307(c)(3)(B) and 307(d) of the CZMA.

While the amended regulations will not include definitions for the terms "directly affecting the coastal zone" and "affecting the coastal zone," guidance in this Supplementary Information in the form of regulatory and legislative history is intended to assist Federal and State agencies, as well as other affected parties, in their efforts to determine when the consistency requirements of the CZMA apply to Federal actions.

In the proposed Federal consistency regulations issued in September 1976, NOAA first adopted the decision, to which it has now returned, of using the threshold terms of the CZMA (i.e., "directly affecting" the coastal zone, and "affecting" the coastal zone) without attempting to define rigidly their meaning, NOAA stated that, "these terms will speak for themselves and difficulties will be addressed on a case-by-case basis" (41 FR 42880, September 26, 1976).

Thereafter, in reproposed regulations issued in August 1977, NOAA attempted to define these terms in response to comments requesting clarification. NOAA prefaced its definition with a statement indicating that a precise definition would be impossible to develop in light of the absence of clear Congressional guidance. Then, based on analogous language in another section of the CZMA as well as language which first appeared as part of the Federal consistency provisions of proposed national land use legislation, NOAA adopted the "significantly affecting" threshold test for section 307(c)(1) of the CZMA (see 42 FR 43590, 43598, August 29, 1977).

Later, in the final consistency regulations issued in March 1978, a new term and definition--"significantly affecting the coastal zone"--was adopted to apply to all Federal actions subject to the consistency requirements of the CZMA. This change was in response to comments suggesting that Congressional intent, although not explicit, appeared to revolve around the need to capture within the consistency requirements only those Federal actions capable of "significantly" affecting the coastal zone (see 43 FR 10511, 10518, March 13, 1978). The Justice Department opinion has led us back to our original view that precise definitions for these terms are impossible to create.

While the legislative history is quite general on the matter, it does set some bounds within which the threshold test may be applied. The Conference Report to the CZMA of 1972 merely restates the statutory language while noting that Federal actions both inside and outside of the coastal zone are captured by the consistency provisions when threshold effects are reached. Other Congressional committee reports reference an interest in "significant" effects on coastal resources. Still other legislative history is written in terms of applying the consistency requirements whenever Federal activities within or adjacent to the coastal zone are determined to have a "functional interrelationship from an economic, social, or geographic standpoint" with lands and waters within the coastal zone.

The consistency provisions are unique and Congress thus far has left the affected parties with a certain amount of discretion to work out the details of their novel intergovernmental

coordination efforts. As a practical matter, States, Federal agencies and other affected parties have not had serious problems in agreeing on whether a Federal action will reach a threshold of impact upon coastal zone resources sufficient to warrant the initiation of the cooperative dialogue called for by the Federal consistency requirements. Intergovernmental coordination has been the general rule because of the benefits which accrue. By virture of the consistency provisions, a decision that a proposed Federal action may impact the coastal zone leads to consultation with the State to ensure that the action will be undertaken in a manner which conforms with the preservation and development criteria within the State's coastal program. Further, the consistency information provides the State with an opportunity to review and comment on the proposal, and assists the State in planning for and managing the anticipated coastal zone effects. Given the advantages to be derived from this process, all affected parties are encouraged to continue to construe liberally the threshold tests to favor inclusion of Federal actions subject to consistency review.

AMENDED REGULATIONS EFFECTIVE IMMEDIATELY

Since the amendments to the regulations described above are required as a matter of law, NOAA hereby finds for good cause in accordance with 5 U.S.C. 553(b) and (d), that notice and public procedures on such regulatory amendments and the 30-day delay prior to the effective date of amendments are unnecessary. Pursuant to section 2.03 of NOAA Directive 21-24, the implementation of Executive Order 12044, NOAA has determined that these regulation amendments are not significant.

For the convenience of the public, the Federal consistency regulation, as amended, are displayed in their entirety to reflect the modifications issued in response to: (i) The requirements of the Outer Continental Shelf Lands Act Amendments of 1978 (see 44 FR 3705, January 18, 1979), (ii) the opinion of the U.S. Department of Justice dated April 20, 1979 (see discussion above), and (iii) the need to provide minor editorial modifications and corrections.

R. L. CARNAHAN,
Assistant Administrator for Administration

JUNE 11, 1979

2. Regulations, 15 CFR 930, Federal Consistency with Approved Coastal Management Programs, Title 15 CFR, revised as of January 1, 1980.

PART 930—FEDERAL CONSISTENCY WITH APPROVED COASTAL MANAGEMENT PROGRAMS

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Subpart H--Secretarial Review Related to the Objectives or Purposes of the Act and National Security Interests

Subpart I--Assistant Administrator Reporting and Continuing Review of Federal Actions Subject to the Federal Consistency Requirements

AUTHORITY: Secs. 307, 316 and 317, Coastal Zone Management Act of 1972, Pub. L. 92-583, 86 Stat. 1280 (16 U.S.C. 1451 et seq.), as amended by Pub. L. 94-370, 90 Stat. 1013.

SOURCE: 44 FR 37143, June 25, 1979, unless otherwise noted.

Subpart A--Objectives

§ 930.1 Overall objectives.

The objectives of these regulations are: (a) To describe the obligations of all agencies, individuals and other parties who are required to comply with the Federal consistency provisions of the Coastal Zone Management Act;

(b) To implement the Federal consistency provisions in a manner which strikes a balance between the need to ensure consistency for Federal actions affecting the coastal zone with approved coastal management and the need to promote Federal programs;

(c) To provide flexible procedures which foster intergovernmental cooperation and minimize duplicative effort and unnecessary delay, while making certain that the objectives of the Federal consistency provisions of the Act are satisfied;

(d) To interpret significant terms in the Federal consistency provisions so that they can be uniformly understood and adhered to by all agencies, individuals and other affected parties;

(e) To provide procedures to make certain that all Federal agency and State agency consistency decisions are directly related to the objectives, policies, standards and other criteria set forth in, or referenced as part of, approved coastal management programs;

(f) To provide procedures which the Secretary, in cooperation with the Executive Office of the President, may use to mediate serious disagreements which arise between Federal and State agencies during the administration of approved coastal management programs;

(g) To provide procedures which permit the Secretary to review Federal license or permit activities, or Federal assistance activities, to determine whether they are consistent with the objectives or purposes of the Act, or are necessary in the interest of national security;

(h) To provide procedures which permit interested parties to notify the Assistant Administrator for Coastal Zone Management of Federal actions believed to be inconsistent with approved coastal management programs, or believed to have been incorrectly determined to be inconsistent with an approved management program; and

(i) To provide procedures for the reporting of any Federal actions found by the Assistant Administrator for Coastal Zone Management to be inconsistent with an approved coastal zone management program, and for the performance review of State implementation of the Federal consis-

tency provisions.

Subpart B—General Definitions

§ 930.10 Index to definitions.

The following list includes all terms defined in Part 930 of this title keyed to the section or paragraph in which they are defined.

Term	Section
Act	930.11
Appellant	930.123
Applicant	930.52
Applicant agency	930.92
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Associated facilities	930.21
Coastal Zone	930.29
Consistent to the maximum extent practicable	930.32
Consistent with the objectives or purposes of the Act	930.121
Development project	930.31(b)
Executive Office of the President	930.14
Failure substantially to comply with an OCS plan	930.86(d)
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Management program	930.19
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OCS plan	930.73
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OMB A-95 process	930.93
Person	930.72
Secretary	930.13
Section	930.12
State agency	930.18

§ 930.11 Act.

The term "Act" means the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1451 et seq.).

§ 930.12 Section.

The term "Section" means a section of the Coastal Zone Management Act of 1972, as amended.

§ 930.13 Secretary.

The term "Secretary" means the Secretary of the U.S. Department of Commerce.

§ 930.14 Executive Office of the President.

The term "Executive Office of the President" means the office, council, board, or other entity within the Executive Office of the President which shall participate with the Secretary in seeking to mediate serious disagreements which may arise between a Federal agency and a coastal State.

§ 930.15 OCZM.

The term "OCZM" means the Office of Coastal Zone Management, National Oceanic and Atmospheric Administration, U.S. Department of Commerce.

§ 930.16 Assistant Administrator.

The term "Assistant Administrator" means the Assistant Administrator for Coastal Zone Management, National Oceanic and Atmospheric Administration, U.S. Department of Commerce.

§ 930.17 Federal agency.

The term "Federal agency" means any department, agency, board, commission, council, independent office or similar entity within the executive branch of the Federal Government, or any wholly owned Federal Government corporation.

§ 930.18 State agency.

(a) The term "State agency" means the agency of the State government designated pursuant to section 306(c)(5) of the Act to receive and administer grants for an approved coastal management program, or a single designee State agency appointed by the 306(c)(5) State agency. Any appointment by the 306(c)(5) State agency of a designee agency must be described in the State's management program. In the absence of such description, all consistency determinations, consistency certifications and Federal assistance proposals shall be sent to and reviewed by the 306(c)(5) State agency.

(b) The State agency is responsible for commenting on Federal agency consistency determinations (see subpart C of this part), concurring with or objecting to consistency certifications for Federal licenses, permits, and Outer Continental Shelf plans (see subparts D and E of this part), and reviewing the consistency of Federal assistance activities proposed by State or local government agencies (see subpart F of this part). The State agency shall be responsible for securing necessary review and comment from other State, regional, or local government agencies. Thereafter, only the State agency is authorized to comment officially on a Federal consistency determination, concur with or object to a consistency

certification, or determine the consistency of a proposed Federal assistance activity.

§ 930.19 Management program.

The term "management program" has the same definition as provided in section 304(11) of the Act, except that for the purposes of this part the term is limited to those management programs adopted to a coastal State in accordance with the provisions of section 306 of the Act, and approved by the Assistant Administrator.

§ 930.20 Coastal zone.

The term "coastal zone" has the same definition as provided in section 304(1) of the Act.

§ 930.21 Associated facilities.

The term "associated facilities" describes all proposed facilities:

(a) Which are specifically designed, located, constructed, operated, adapted, or otherwise used, in full or in major part, to meet the needs of a Federal action (e.g., activity, development project, license, permit, or assistance), and

(b) Without which the Federal action, as proposed, could not be conducted. All further requirements in this part related to the review of and consistency for Federal activities including development project (see subpart C of this part), Federal license and permit activities (see subparts D and E of this part) and Federal assistance activities (see subpart F of this part) also apply to associated facilities related to those Federal actions. Therefore, the proponent of a Federal action must consider whether the Federal action and its associated facilities affect the coastal zone and, if so, whether these interrelated activities satisfy the relevant consistency requirement of the Act.

Subpart C--Consistency for Federal Activities

§ 930.30 Objectives.

The provisions of this subpart are provided to assure that all Federally conducted or supported activities including development projects directly affecting the coastal zone are undertaken in a manner consistent to the maximum extent practicable with approved State coastal management programs.

§ 930.31 Federal activity.

(a) The term "Federal activity" means any functions performed by or on behalf of a Federal agency in the exercise of its statutory responsibilities.

(b) A Federal development project is a Federal activity involving the planning, construction, modification, or removal of public works, facilities, or other structures, and the acquisition, utilization, or disposal of land or water resources.

(c) The term "Federal activity" does not include the issuance of a Federal license or permit to an applicant or person (see subparts D and E of this part) or the granting of Federal assistance to an applicant agency (see subpart F of this part).

§ 930.32 Consistent to the maximum extent practicable.

(a) The term "consistent to the maximum extent practicable" describes the requirement for Federal activities including development projects directly affecting the coastal zone of States with approved management programs to be fully consistent with such programs unless compliance is prohibited based upon the requirements of existing law applicable to the Federal agency's operations. If a Federal agency asserts that compliance with the management program is prohibited, it must clearly describe to the State agency the statutory provisions, legislative history, or other legal authority which limits the Federal agency's discretion to comply with the provisions of the management program.

The duty the Act imposes upon Federal agencies is not set aside by virtue of section 307(e). The Act was intended to cause substantive changes in Federal agency decisionmaking within the context of the discretionary powers residing within such agencies. Accordingly, when read together, sections 307(c)(1) and (2) and 307(e) require Federal agencies, whenever legally permissible, to consider State-management programs as supplemental requirements to be adhered to in addition to existing agency mandates.

(b) A Federal agency may deviate from full consistency with an approved management program when such deviation is justified because of some unforeseen circumstances arising after the approval of the management program which present the Federal agency with a substantial obstacle that prevents complete adherence to the approved program.

§ 930.33 Identifying Federal activities directly affecting the coastal zone.

(a) Federal agencies shall determine which of their activities directly affect the coastal zone of States with approved management programs.

(b) Federal agencies shall consider all development projects within the coastal zone to be activities directly affecting the coastal

zone. All other types of activities within the coastal zone are subject to Federal agency review to determine whether they directly affect the coastal zone.

(c) Federal activities outside of the coastal zone (e.g., on excluded Federal lands, on the Outer Continental Shelf, or landward of the coastal zone) are subject to Federal agency review to determine whether they directly affect the coastal zone.

§ 930.34 Federal agency consistency determinations.

(a) Federal agencies shall provide State agencies with consistency determinations for all Federal activities directly affecting the coastal zone. The Federal agency may provide the State agency with this information in any manner it chooses so long as the requirements of this Subpart are satisfied.

(b) Federal agencies shall provide State agencies with a consistency determination at the earliest practicable time in the planning or reassignment of the activity. A consistency determination should be prepared following developmenmt of sufficient information to determine reasonably the consistency of the activity with the State's management program, but before the Federal agency reaches a significant point of decisionmaking in its review process. The consistency determination shall be provided to State agencies at least 90 days before final approval of the Federal activity unless both the Federal agency and the State agency agree to alternative notification schedule.

§ 930.35 Federal and State agency coordination.

(a) State agencies should list in their management programs Federal activities which, in the opinion of the State agency, are likely to directly affect the coastal zone and require a Federal agency consistency determination. Listed Federal activities must be described in terms of the specific type of activity involved (e.g., Federal reclamation projects). In the event the State agency chooses to describe Federal activities outside of the coastal zone but likely to directly affect the coastal zone, it must also describe the geographic location of such activities (e.g., reclamation projects in coastal floodplains).

(b) State agencies should monitor unlisted Federal activites (e.g., by use of OMB Circular A-95 review, review of National Environmental Policy Act (NEPA) environmental impact statements, etc.) and should notify Federal agencies of unlisted Federal activities which Federal agencies have not subjected to a consistency review but which, in the opinion of the State agency, directly affect the coastal zone and require a Federal agency consistency determination. State agencies must notify Federal agencies within 45 days from receipt of notice of the unlisted Federal activity, otherwise the State agency waives its right to request a consistency determination. The waiver does not apply in cases where the State agency does not receive notice of the Federal activity (e.g., for those Federal activities which are not processed through A-95 review, NEPA review or a similar procedure which permits State agency monitoring).

(c) The recommended listing and monitoring procedures described in paragraphs (a) and (b) of this section are neither a substitute for nor eliminate Federal agency responsibility under §§ 930.33(b) and 930.34 to provide State agencies with consistency determinations for all development projects in the coastal zone and for all other Federal activities which the Federal agency finds directly affect the coastal zone.

(d) If a Federal agency decides that a consistency determination is not required for a Federal activity (1) identified by a State agency on its list or through case-by-case monitoring, (2) which is the same as or similar to activities for which consistency determinations have been prepared in the past, or (3) for which the Federal agency undertook a thorough consistency assessment and developed initial findings on the effects of the activity on the coastal zone, the Federal agency shall provide the State agency with a notification, at the earliest practicable time in the planning of the activity briefly setting forth the reasons for its negative determination. A negative determination shall be provided to the State agency at least 90 days before final approval of the activity, unless both the Federal agency and the State agency agree to an alternative notification schedule.

§ 930.36 Availability of mediation for negative determination disputes.

In the event of a serious disagreement between a Federal agency and a State agency regarding a determination related to whether a proposed activity directly affects the coastal zone, either party may seek the Secretarial mediation services provided for in Subpart G.

§ 930.37 Consistency determinations for proposed activities.

(a) Federal agencies shall review their proposed Federal activities which directly affect the coastal zone in order to develop consistency determinations which indicate whether such activities will be undertaken in a manner consistent to the maximum extent practicable with approved State management programs. Federal agencies are encouraged to consult with State agencies during their efforts to assess

whether such activities will be consistent to the maximum extent practicable with such programs.

(b) In cases where Federal agencies will be performing repeated activity other than a development project (e.g., ongoing maintenance, waste disposal, etc.) which cumulatively has a direct effect upon the coastal zone, the agency may develop a general consistency determination thereby avoiding the necessity of issuing separate consistency determinations for each incremental action controlled by the major activity. A general consistency determination may only be used in situtations where the incremental actions are repetitive or periodic, substantially similar in nature, and do not directly affect the coastal zone when performed separately. If a Federal agency issues a general consistency determination, it must thereafter periodically consult with the State agency to discuss the manner in which the incremental actions are being undertaken.

(c) In cases where the Federal agency has sufficient information to determine the consistency of a proposed development project from planning to completion, only one consistency determination will be required. However, in cases where major Federal decisions related to a proposed development project will be made in phases based upon developing information, with each subsequent phase subject to Federal agency discretion to implement alternative decisions based upon such information (e.g., planning, siting, and design decisions), a consistency determination will be required for each major decision. In cases of phased decisionmaking, Federal agencies shall ensure that the development project continues to be consistent to the maximum extent practicable with the State's management program.

§ 930.38 Consistency determinations for activities initiated prior to management program approval.

(a) A consistency determination will be required for ongoing Federal activities other than development projects (e.g., waste disposal practices) initiated prior to management program approval, which are governed by statutory authority under which the Federal agency retains discretion to reassess and modify the activity. In these cases the consistency determination must be made by the Federal agency at the earliest practicable time following management program approval, and the State agency must be provided with a consistency determination no later than 120 days after management program approval for ongoing activities which the State agency lists or identifies through monitoring as subject to consistency with the management program.

(b) A consistency determination shall be required for major, phased Federal development project decisions described in § 930.37(c) which are made following management program approval and are related to development projects initiated prior to program approval. In making these new decisions, Federal agencies shall consider coastal zone effects not fully evaluated at the outset of the project. This provision shall not apply to phased Federal decisions which were specifically described, considered and approved prior to management program approval (e.g., in a final environmental impact statement issued pursuant to the National Environmental Policy Act).

§ 930.39 Content of a consistency determination.

(a) The consistency determination shall include a brief statement indicating whether or not the proposed activity will be undertaken in a manner consistent to the maximum extent practicable with the management program. The statement must be based upon an evaluation of the relevant provisions of the management program. The consistency determination shall also include a detailed description of the activity, its associated facilities, and their coastal zone effects, and comprehensive data and information sufficient to support the Federal agency's consistency statement. The amount of detail in the statement evaluation, activity description and supporting information shall be commensurate with the expected effects of the activity on the the coastal zone.

(b) Federal agencies shall be guided by the following in making their consistency determinations. The activity (e.g., project siting and construction), its direct effects (e.g., air, water, waste discharges, etc.), and associated facilities (e.g., proposed siting and construction of access road, connecting pipeline, support buildings, etc.) and the direct effects of the associated facilities (e.g., erosion, wetlands, beach access impacts, etc.) must all be consistent to the maximum extent practicable with the management program. Although nonassociated facilities (e.g., recreational housing which is induced by but not necessarily related to a Federal harbor dredging project--see § 930.21) must be included within the consistency determination's description of the direct effects of the activity, Federal agencies are not responsible for evaluating the consistency of such facilities.

(c) In making their consistency determinations, Federal agencies shall give appropriate weight to the various types of provisions within the management program. Federal agencies must ensure that their activities are consistent to the maximum extent practicable with the enforceable, mandatory policies of the management program. However, Federal agencies need only give adequate consideration to management program provisions which are in the nature of recommen-

dations. Finally, Federal agencies do not have to evaluate coastal zone effects for which the management program does not contain mandatory or recommended policies because, in the absence of such provisions, there is no basis for making a consistency determination with respect to such effects.

(d) When Federal agency standards are more restrictive than standards or requirements contained in the State's management program, the Federal agency may continue to apply its stricter standards (e.g., restrict project development or design alternatives notwithstanding permissive management program policies). In such cases the Federal agency should inform the State agency in the consistency determination of the statutory, regulatory or other basis for the application of the stricter standards.

§ 930.40 Multiple Federal agency participation.

Whenever more than one Federal agency is involved in conducting or supporting a Federal activity or its associated facilities directly affecting the coastal zone, or is involved in a group of Federal activities related to each other because of their geographic proximity, consideration should be given to the preparation of one consistency determination for all the Federal activities involved. In such cases, Federal agencies should consider joint preparation or lead agency development of the consistency determination. In either case, the consistency determination (a) must be transmitted to the State agency at least 90 days before final decisions are taken by any of the participating agencies, (b) must indicate whether or not each of the proposed activities is consistent to the maximum extent practicable with the management program and (c) must include information on each proposed activity sufficient to support the consistency determination.

§ 930.41 State agency response.

(a) A State agency shall inform the Federal agency of its agreement or disagreement with the Federal agency's consistency determination at the earliest practicable time. If a final response has not been developed and issued within 45 days from receipt of the Federal agency notification, the State agency should at that time inform the Federal agency of the status of the matter and the basis for further delay. The Federal agency may presume State agency agreement if the State agency fails to provide a response within 45 days from receipt of the Federal agency notification.

(b) State agency agreements shall not be presumed in cases where the State agency, with the 45 day period, requests an extension of time to review the matter. Federal agencies shall approve one request for an extension period of 15 days or less. In considering whether a longer or additional extension period is appropriate, the Federal agency should consider the magnitude and complexity of the information contained in the consistency determination.

(c) Final Federal agency action may not be taken sooner than 90 days from the issuance of the consistency determination to the State agency unless both the Federal agency and the State agency agree to an alternative period (see § 930.34(b)).

§ 930.42 State agency disagreement.

(a) In the event the State agency disagrees with the Fedeal agency's consistency determination, the State agency shall accompany its response to the Federal agency with its reasons for the disagreement and supporting information. The State agency response must describe (1) how the proposed activity will be inconsistent with specific elements of the management program, and (2) alternative measures (if they exist) which, if adopted by the Federal agency, would allow the activity to proceed in a manner consistent to the maximum extent practicable with the management program.

(b) If the State agency's disagreement is based upon a finding that the Federal agency has failed to supply sufficient information (see § 930.39(a)), the State agency's response must describe the nature of the information requested and the necessity of having such information to determine the consistency of the Federal activity with the management program.

(c) State agencies shall send to the Assistant Administrator a copy of responses which describe disagreements with Federal agency consistency determinations.

§ 930.43 Availability of mediation for disputes concerning proposed activities.

(a) In the event of a serious disagreement between a Federal agency and a State agency regarding the consistency of a proposed Federal activity directly affecting the coastal zone, either party may request the Secretarial mediation services provided for in Subpart G.

§ 930.44 Availability of mediation for previously reviewed activities.

(a) Federal and State agencies shall cooperate in their efforts to monitor Federally approved activities in order to make certain that such activities continue to be undertaken in a manner consistent to the maximum extent practicable, with the State's management program.

(b) The State agency shall request that the Federal agency take appropriate remedial action following a serious disagreement resulting from a State agency's objection to a Federal activity which was: (i) previously determined to be con-

sistent to the maximum extent practicable with the State's management program, but which the State agency later maintains is being conducted or is having a coastal zone effect substantially different than originally proposed and, as a result, is no longer consistent to the maximum extent practicable with the State's management program, or (ii) previously determined not to be a Federal activity directly affecting the coastal zone, but which the State agency later maintains is being conducted or is having a coastal zone effect substantially different than originally proposed and, as a result, the activity directly affects the coastal zone and is not consistent to the maximum extent practicable with the State's management program. The State agency's request must include supporting information and a proposal for recommended remedial action.

(c) If, after a reasonable time following a request for remedial action, the State agency still maintains that a serious disagreement exists, either party may request the Secretarial mediation services for in Subpart G.

Subpart D—Consistency for Activities Requiring a Federal License or Permit

§ 930.50 Objectives.

The provisions of this subpart are provided to assure that Federally licensed or permitted activities affecting the coastal zone are conducted in a manner consistent with approved management programs.

§ 930.51 Federal license or permit.

(a) The term "Federal license or permit" means any authorization, certification, approval, or other form of permission which any Federal agency is empowered to issue to an applicant.

(b) The term also includes the following types of renewals and major amendments which affect the coastal zone:

(1) Renewals and major amendments of Federal license and permit activities not previously reviewed by the State agency:

(2) Renewals and major amendments of Federal license and permit activities previously reviewed by the State agency which are filed after and are subject to management program amendments not in existence at the time of original State agency review; and

(3) Renewals and major amendments of Federal license and permit activities previously reviewed by the State agency which will cause coastal zone effects substantially different than those originally reviewed by the State agency.

§ 930.52 Applicant.

The term "applicant" means any individual, public or private corporation, partnership, association, or other entity organized or existing under the laws of any State, or any State, regional, or local government, who, following management program approval, files an application for a Federal license or permit to conduct an activity affecting the coastal zone. The term "applicant" does not include Federal agencies applying for Federal licenses or permits. Federal agency "activities" requiring Federal licenses or permits are subject to the consistency requirements of subpart C of this Part.

§ 930.53 Management program license and permit listing.

(a) During management program development, Federal agencies should assist State agencies in identifying Federal license and permit activities which reasonably can be expected to affect the coastal zone.

(b) State agencies shall develop a list of Federal license and permit activities which are likely to affect the coastal zone and which the State agency wishes to review for consistency with the management program. The list shall be included as part of the management program and the Federal license and permit acitivities shall be described in terms of the specific licenses or permits involved (e.g., Corps of Engineers 404 permits, Coast Guard bridge permits, etc.). In the event the State agency chooses to review Federal licenses and permits for activities outside the coastal zone but likely to affect the coastal zone, it must generally describe the geographic location of such activities.

(c) If a State agency wishes to avoid repeated review of minor Federally permitted activities which, while individually inconsequential, cumulatively cause effects on the coastal zone, the State agency, after developing conditions allowing concurrence for such activities, may issue a general public notice (see § 930.61) and general concurrence allowing similar minor work in the same geographic area to proceed without prior State agency review. In such cases, the State agency must set forth in the management program license and permit list the minor Federal license and permit acitivities and the relevent conditions which are covered by the general concurrence. Minor Federal license or permit activities which satisfy the conditions of the general concurrence are not subject to the consistency certification requirement of this subpart. Except in cases where the State agency indicates otherwise, copies of Federal license or permit applications for activities subject to a general concurrence must be sent by the applicant to the State agency to allow the State agency to monitor adherence to the conditions required by such

concurrence. Confidential and proprietary material within such applications may be deleted.

(d) The license and permit list may be amended by the State agency following consultation with the affected Federal agency and approval of additions or deletions by the Assistant Administrator. The State agency shall provide copies of the list and any amendments to Federal agencies and shall make the information available to the public.

(e) No Federal license or permit described on an approved list shall be issued by a Federal agency until the requirements of this subpart have been satisfied. Federal agencies shall inform applicants for listed licenses and permits of the requirements of this subpart.

§ 930.54 Unlisted Federal license and permit activities.

(a) With the assistance of Federal agencies, State agencies should monitor unlisted Federal license and permit activities (e.g., by use of OMB Circular A-95 review, review of NEPA environmental impact statements, etc.) and shall immediately notify Federal agencies and applicants of unlisted activities affecting the coastal zone which require State agency review. State agencies must inform the Federal agency and applicant within 30 days from notice of the license or permit application, otherwise the State agency waives its right to review the unlisted activity. The waiver does not apply in cases where the State agency does not receive notice of the Federal license or permit activity.

(b) The State agency must also notify the Assistant Administrator of unlisted Federal license or permit activities which the State agency believes should be subject to State agency review. Following State agency notification to the Federal agency, applicant and the Assistant Administrator, the Federal agency may not issue the license or permit until the requirements of this Subpart have been satisfied, unless the Assistant Administrator disapproves the State agency decision to review the activity.

(c) The Federal agency and the applicant have 15 days from receipt of the State agency notice to provide comments to the Assistant Administrator regarding the State agency's decision to review the activity. The sole basis for the Assistant Administrator's approval or disapproval of the State agency's decision will relate to whether the proposed activity can be reasonably expected to affect the coastal zone of the State. The Assistant Administrator shall issue a decision, with supporting comments, to the State agency, Federal agency and applicant with 30 days from receipt of the State agency notice.

(d) In the event of disapproval by the Assistant Administrator, the Federal agency may approve the license or permit application and the applicant need not comply with the requirements of this subpart. If the Assistant Administrator approves the State agency's decision, the Federal agency and applicant must comply with the consistency certification procedures of this subpart.

(e) Following an approval by the Assistant Administrator, the applicant shall amend the Federal application by including a consistency certification and shall provide the State agency with a copy of the certification along with necessary supporting data and information (see §§ 930.63 and 930.64). For the purposes of this section, concurrence by the State agency shall be conclusively presumed in the absence of a State agency objection within six months from the original Federal agency notice to the State agency (see paragraph (a) of this section) or within three months from receipt of the applicant's consistency certification and accompanying information, whichever period terminates last.

§ 930.55 Availability of mediation for license or permit disputes.

In the event of a serious disagreement between a Federal and State agency regarding whether a listed or unlisted Federal license or permit activity is subject to consistency review, either party may request the Secretarial mediation services provided for in subpart G; notice shall be provided to the applicant. The existence of a serious disagreement will not relieve the Federal agency from the responsibility for withholding approval of a license or permit application for an activity on an approved management program list (see § 920.53) or individually approved by the Assistant Administrator (see § 930.54) pending satisfaction of the requirements of this subpart. Similarly, the existence of a serious disagreement will not prevent the Federal agency from approving a license or permit activity which has not received Assistant Administrator approval.

§ 930.56 State agency guidance and assistance to applicants; information requirements.

(a) As a preliminary matter, any applicant for a Federal license or permit selected for review by a State agency should obtain the views and assistance of that agency regarding the means for ensuring that the proposed activity will be conducted in a manner consistent with the State's management program. As part of its assistance efforts, the State agency shall make available for public inspection copies of the management program document.

(b) The management program as originally approved or amended may describe requirements regarding the data and information necessary

to assess the consistency of Federal license and permit activities. Required data and information may not include confidential and proprietary material. In the case of approved amendments. State agencies shall send copies to relevant Federal agencies who shall in turn, provide the information requirements to applicants. If a State does not choose to develop or amend its management program to include information requirements, the applicant must, at a minimum, supply the State agency with the information required by § 930.58.

§ 930.57 Consistency certifications.

(a) When satisfied that the proposed activity meets the Federal Consistency requirements of this subpart, all applicants for Federal licenses or permits subject to State agency review shall provide in the application to the Federal licensing or permitting agency a certification that the proposed activity complies with and will be conducted in a manner consistent with the State's approved management program. At the same time, the applicant shall furnish to the State agency a copy of the certification.

(b) The applicant's consistency certification shall be in the following form: "The proposed activity complies with (name of State) approved coastal management program and will be conducted in a manner consistent with such program."

§ 930.58 Necessary data and information.

(a) The applicant shall furnish the State agency with necessary data and information along with the consistency certification. Such information and data shall include the following:

(1) A detailed description of the proposed activity and its associated facilities which is adequate to permit an assessment of their probable coastal zone effects. Maps, diagrams, technical data and other relevant material must be submitted when a written description alone will not adequately describe the proposal (a copy of the Federal application and all supporting material provided to the Federal agency should also be submitted to the State agency).

(2) Information required by the State agency pursuant to § 930.56(b).

(3) A brief assessment relating the probable coastal zone effects of the proposal and its associated facilities to the relevant elements of the management program.

(4) A brief set of findings, derived from the assessment, indicating that the proposed activity (e.g., project siting and construction), its associated facilities (e.g., access road, support buildings), and their effects (e.g., air, water, waste discharges, erosion, wetlands, beach access impacts) are all consistent with the provisions of the management program. In developing findings, the applicant shall give appropriate weight to the various types of provisions within the management program. While applicants must be consistent with the enforceable, mandatory policies of the management program, they need only demonstrate adequate consideration of policies which are in the nature of recommendations. Applicants need not make findings with respect to coastal zone effects for which the management program does not contain mandatory or recommended policies.

(b) At the request of the applicant, interested parties who have access to information and data required by subparagraph (a)(1) and (2) of this section may provide the State agency with all or part of the material required. Furthermore, upon request by the applicant, the State agency shall provide assistance for developing the assessment and findings required by paragraphs (a)(3) and (4) of this section.

(c) When satisfied that adequate protection against public disclosure exists, applicants should provide the State agency with confidential and proprietary information which the State agency maintains is necessary to make a reasoned decision on the consistency of the proposal. State agency requests for such information must be related to the necessity of having such information to assess adequately the coastal zone effects of the proposal.

§ 930.59 Multiple permit review.

(a) Applicants shall, to the extent practicable, consolidate related Federal license and permit activities affecting the coastal zone for State agency review. State agencies shall, to the extent practicable, provide applicants with a "one-stop" multiple permit review for consolidated permits to minimize duplication of effort and to avoid unnecessary delays.

(b) A State agency objection to one or more of the license or permit activities submitted for consolidated review shall not prevent the applicant from receiving Federal agency approval for those license and permit activities found to be consistent with the management program.

§ 930.60 Commencement of State agency review.

(a) Except as provided in § 930.54(e), State agency review of an applicant's consistency certification begins at the time the State agency receives a copy of the consistency certification, and the information and data required pursuant to § 930.58.

(b) A State agency request for information or data in addition to that required by § 930.58 shall not extend the date of commencement of State agency review.

§ 930.61 Public notice.

(a) Following receipt of the material described in § 930.60 the State agency shall ensure timely public notice of the proposed activity. At a minimum the provision of public notice must be in accordance with State law. In addition, public notice must be provided in the immediate area of the coastal zone which is likely to be affected by the proposed activity. Public notice shall be expanded in proportion to the degree of likely public interest resulting from the unique geographic area involved, the substantial commitment of or impact on coastal resources, the complexity or controversy of the proposal, or for other good cause.

(b) Public notice shall facilitate public comment by providing a summary of the proposed activity, by announcing the availability for inspection of the consistency certification and accompanying public information and data, and by requesting that comments be submitted to the State agency.

(c) A number of procedural options, if permitted by State law, are available to State agencies to satisfy the public notice requirements of this Subpart. They include, but are not limited to:

(1) the State agency providing the public notice;

(2) the State agency requiring the applicant to provide the public notice; or

(3) the State agency relying upon the public notice provided by the Federal agency reviewing the application for the Federal license or permit (e.g., A-95 public notices, notice of availability of NEPA environmental impact statements) if such notice satisfies the minimum requirements set forth in paragraphs (a) and (b) of this section.

(d) Federal and State agencies are encouraged to issue joint public notices whenever possible to minimize duplication of effort and to avoid unnecessary delays.

§ 930.62 Public hearings.

(a) At the discretion of the State agency, public notice may include the announcement of one or more public hearings. Public hearings shall be scheduled with a view towards (1) allowing access to the consistency certification and accompanying public information within a reasonable time prior to the hearing, (2) facilitating broad public attendance and participation at the hearing, and (3) affording the applicant expeditious consideration of the proposed activity.

(b) Federal and State agencies are encouraged to hold joint public hearings in the event both agencies determine that a hearing on the action is necessary.

§ 930.63 State agency concurrent with a consistency certification.

(a) At the earliest practicable time, the State agency shall notify the Federal agency and the applicant whether the State agency concurs with or objects to a consistency certification. Concurrence by the State agency shall be conclusively presumed in the absence of a State agency objection within six months following commencement of State agency review.

(b) State agencies should restrict the period of public notice, receipt of comments, hearing proceedings and final decision-making to the minimum time necessary to inform the public, obtain sufficient comment, and develop a reasonable decision on the matter. If the State agency has not issued a decision within three months following commencement of State agency review, it shall notify the applicant and the Federal agency of the status of the matter, and the basis for further delay.

(c) If the State agency issues a concurrence or is conclusively presumed to concur with the applicant's consistency certification, the Federal agency may approve the Federal license or permit application. Notwithstanding State agency concurrence with a consistency certification, the Federal permitting agency may deny approval of the Federal license or permit application. Federal agencies should not delay processing applications pending receipt of a State agency's concurrence. In the event a Federal agency determines that an application will not be approved, it shall immediately notify the applicant and the State agency.

§ 930.64 State agency objection to a consistency certification.

(a) If the State agency objects to the applicant's consistency certification within six months following commencement of review, it shall notify the applicant, Federal agency and Assistant Administrator of the objection.

(b) State agency objections must describe (1) how the proposed activity is inconsistent with specific elements of the management program, and (2) alternative measures (if they exist) which, if adopted by the applicant, would permit the proposed activity to be conducted in a manner consistent with the management program.

(c) During the period when the State agency is reviewing the consistency certification, the applicant and the State agency should attempt to agree upon conditions, which, if met by the applicant, would permit State agency concurrence. The parties shall also consult with the Federal agency responsible for approving the Federal license or permit to ensure that proposed conditions satisfy Federal as well as State management program requirements.

(d) A State agency objection may be based

upon a determination that the applicant has failed, following a written State agency request, to supply the information required pursuant to § 903.58. If the State agency objects on the grounds of insufficient information, the objection must describe the nature of the information requested and the necessity of having such information to determine the consistency of the activity with the management program.

(e) A State agency objection shall include a statement informing the applicant of a right of appeal to the Secretary on the grounds described in Subpart H.

§ 930.65 Federal permitting agency responsibility.

Following receipt of a State agency objection to a consistency certification, the Federal agency shall not issue the Federal license or permit except as provided in Subpart H of this part.

§ 930.66 Availability of mediation for previously reviewed activities.

(a) Federal and State agencies shall cooperate in their efforts to monitor Federally licensed and permitted activities in order to make certain that such activities continue to conform to both Federal and State requirements.

(b) The State agency shall request that the Federal agency take appropriate remedial action following a serious disagreement resulting from a State agency objection to a Federally licensed or permitted activity which was: (1) Previously determined to be consistent with the State's management program, but which the State agency later maintains is being conducted or is having coastal zone effects substantially different than originally proposed and, as a result, is no longer consistent with the State's management program; or (2) previously determined not to be an activity affecting the coastal zone, but which the State agency later maintains is being conducted or is having coastal effects substantially different than originally proposed and, as a result, the activity affects the coastal zone in a manner inconsistent with the State's management program. The State agency's request must include supporting information and a proposal for recommended remedial action; a copy of the request must be sent to the applicant.

(c) If, after a reasonable time following a request for remedial action, the State agency still maintains that a serious disagreement exists with the Federal agency, either party may seek the Secretarial mediation services provided for in Subpart G of this part.

Subpart E--Consistency for Outer Continental Shelf (OCS) Exploration, Development and Production Activities

§ 930.70 Objectives.

The provisions of this subpart are provided to assure that all Federal license and permit activities described in detail in OCS plans and which affect the coastal zone are conducted in a manner consistent with approved coastal zone management programs.

§ 930.71 Federal license or permit activity described in detail.

The term "Federal license or permit activity described in detail" means any activity requiring a Federal license or permit, as defined in § 930.51, which the Secretary of the Interior determines must be described in detail within an OCS plan.

§ 930.72 Person.

The term "person" means any individual, corporation, partnership, association, or other entity organized or existing under the laws of any State, the Federal government, any State, regional, or local government, or any entity of such Federal, State, regional or local government, who submits to the Secretary of the Interior, or designee following management program approval, an OCS plan which describes in detail Federal license or permit activities.

§ 930.73 OCS plan.

(a) The term "OCS plan" means any plan for the exploration or development of, or production from, any area which has been leased under the Outer Continental Shelf Lands Act (43 U.S.C. Sec. 1331 et seq.), and the regulations under that Act, which is submitted to the Secretary of the Interior or designee following management program approval and which describes in detail Federal license or permit activities.

(b) The requirements of this subpart do not apply to Federal license and permit applications filed after management program approval for activities described in detail in OCS plans approved by the Secretary of the Interior or designee prior to management program approval.

§ 930.74 OCS activities subject to State agency review.

Except for States which do not anticipate coastal zone effects resulting from OCS activities, management program lists required pursuant to § 930.53 shall include a reference to OCS plans which describe in detail Federal license and permit activities affecting the coastal zone.

§ 930.75 State agency assistance to persons; information requirements.

(a) As a preliminary matter, any person intending to submit to the Secretary of the Interior and OCS plan which describes in detail Federal license or permit activities affecting the coastal zone should obtain the views and assistance of the State agency regarding the means for ensuring that such activities will be conducted in a manner consistent with the State's management program. As part of its assistance efforts, the State agency shall make available for inspection copies of the management program document.

(b) In accordance with the provisions in § 930.56(b), the management program as originally approved or amended may describe requirements regarding data and information which will be necessary for the State agency to assess the consistency of the Federal license and permit activities described in detail in OCS plans.

§ 930.76 Submission of an OCS plan and consistency certification.

Any person submitting to the Secretary of the Interior or designee any OCS plan shall:

(a) Identify all activities described in detail in the plan which are subject to State agency review:

(b) When satisfied that the proposed activities meet the Federal consistency requirements of this Subpart, provide the Secretary of the Interior or designee with a consistency certification, attached to the OCS plan, and the Secretary of the Interior or designee shall furnish the State agency a copy of the OCS plan (excluding proprietary information) and consistency certification.

(c) The person's consistency certification shall be in the following form:

The proposed activities described in detail in this plan comply with (name of State(s)) approved coastal management program(s) and will be conducted in a manner consistent with such program(s).

§ 930.77 Necessary data and information.

(a) The State agency shall use the information received pursuant to the Department of the Interior's operating regulations governing exploration, development and production operations on the OCS (see 30 CFR § 250.34) and regulations pertaining to the OCS information program (see 30 CFR Part 252) to determine the consistency of proposed Federal license and permit activities described in detail in OCS plans.

(b) The person shall supplement the information provided by paragraph (a) of this section by supplying the State agency with:

(1) Information required by the State agency pursuant to § 930.75(b).

(2) A brief assessment relating the probable coastal zone effects of the activities and their associated facilities to the relevant elements of the management program, and

(3) A brief set of findings, derived from the assessment, indicating that each of the proposed activities (e.g., drilling, platform placement) and their associated facilities (e.g., onshore support structures, offshore pipelines), and their effect (e.g., air, water, waste discharge, erosion, wetlands, beach access impacts) are all consistent with the provisions of the management program. In developing findings, the person shall give appropriate weight to the various provisions within the management program in accordance with the guidance provided in § 930.58(a)(4).

(c) At the request of the person, interested parties who have access to information required by paragraphs (a) and (b)(1) of this section may provide the State agency with all or part of the material required. Furthermore, upon request by the person, the State agency shall provide assistance for developing the assessment and findings required by paragraph (b)(2) and (3) of this section.

(d) When satisfied that adequate protection against public disclosure exists, persons should provide the State agency with confidential and proprietary information which the State agency maintains is necessary to make a reasoned decision on the consistency of the proposed activities. State agency requests for such information must be related to the necessity of having such information to assess adequately the coastal zone effects of the proposed activities.

§ 930.78 Commencement of State agency review; public notice.

(a) State agency review of the person's consistency certification begins at the time the State agency receives a copy of the OCS plan, consistency certification, and required necessary data and information. A State agency request for information and data in addition to that required by § 930.77 shall not extend the date of commencement of State agency review.

(b) Following receipt of the material described in paragraph (a) of this section, the State agency shall ensure timely public notice of the proposed activities in accordance with the directives within §§ 930.61-930.62.

§ 930.79 State agency concurrence or objection.

(a) At the earliest practicable time, the State agency shall notify the person, the Secretary of the Interior or designee and the Assistant Adminstrator of its concurrence with or objection to the consistency certification.

State agencies should restrict the period of public notice, receipt of comments, hearing proceedings and final decision-making to the minimum time necessary to inform the public, obtain sufficient comment, and develop a reasonable decision on the matter. If the State agency has not issued a decision within three months following commencement of State agency review, it shall notify the person, the Secretary of the Interior or designee and the Assistant Administrator of the status of review and the basis for further delay in issuing a final decision. Notice shall be in written form and postmarked no later than three months following the State agency's receipt of the certification and supporting information. Concurrence by the State agency shall be conclusively presumed if the notification required by this subparagraph is not provided.

(b) Concurrence by the State agency shall be conclusively presumed in the absence of a State agency objection to the consistency certification within six months following commencement of State agency review.

(c) If the State agency objects to one or more of the Federal license or permit activities described in detail in the OCS plan, it must provide a separate discussion for each objection in accordance with the directives within §930.64(b) and (d). The objection shall also include a statement informing the person of a right of appeal to the Secretary on the grounds described in Subpart H.

§ 930.80 Effect of State agency concurrence.

(a) If the State agency issues a concurrence or is conclusively presumed to concur with the person's consistency certification, the person will not be required to submit additional consistency certifications and supporting information for State agency review at the time Federal applications are actually filed for the Federal licenses and permits to which such concurrence applies.

(b) Unless the State agency indicates otherwise, copies of Federal license and permit applications for activities described in detail in an OCS plan which has received State agency concurrence shall be sent by the person to the State agency to allow the State agency to monitor the activities. Confidential and proprietary material within such applications may be deleted.

§ 930.81 Federal permitting agency responsibility.

Following receipt of a State agency objection to a consistency certification related to Federal license or permit activities described in detail in an OCS plan, the Federal agency shall not issue any of such licenses or permits except as provided in Subpart H of this part.

§ 930.82 Multiple permit review.

(a) A person submitting a consistency certification for Federal license or permit activities described in detail in an OCS plan is strongly encouraged to work with other Federal agencies in an effort to include, for consolidated State agency review, consistency certification and supporting data and information applicable to OCS-related Federal license and permit activities affecting the coastal zone which are not required to be described in detail in OCS plans but which are subjected to State agency consistency review (e.g., Corps of Engineer permits for the placement of structures on the OCS and for dredging and the transportation of dredged material, Environmental Protection Agency air and water quality permits for offshore operations and onshore support and processing facilities, etc.). In the event the person does not consolidate such OCS-related permit activities with the State agency's review of the OCS plan, such activities will remain subject to individual State agency review under the requirements of Subpart D of this part.

(b) A State agency objection to one or more of the OCS-related Federal license or permit activities submitted for consolidated review shall prevent the person from receiving Federal agency approval (1) for those OCS-related license or permit activities found by the State agency to be consistent with the management program, and (2) for the license and permit activities described in detail in the OCS plan provided the State agency concurs with the consistency certification for such plan. Similarly, a State agency objection to the consistency certification for an OCS plan shall not prevent the person from receiving Federal agency approval for those OCS-related license or permit activities determined by the State agency to be consistent with the management program.

§ 930.83 Amended or new OCS plans.

If the State agency objects to the person's OCS plan consistency certification, and if, pursuant to subpart H, the Secretary does not determine that each of the objected to Federal license or permit activities described in detail in such plan is consistent with the objectives or purposes of the Act, or is necessary in the interest of national security, the person shall submit an amended or new plan to the Secretary of the Interior or designee and to the State agency along with a consistency certification and data and information necessary to support the new consistency determination. The data and information shall specifically describe modifications made to the original OCS plan, and the manner in which such modifications will ensure that all of the proposed Federal license or permit activities described in detail in the amended or new plan will be conducted in

a manner consistent with the State's management program.

§ 930.84 Review of amended or new OCS plans; public notice.

(a) After receipt of a copy of the amended or new OCS plan, consistency certification, and accompanying data and information, State agency review shall begin.

(b) Following receipt of the material described in paragraph (a) of this section, the State agency shall ensure timely public notice of the proposed activities in accordance with the directives within §§ 930.61-930.62.

(c) The State agency shall concur with or object to the person's consistency certification in accordance with the directives within § 930.79, except that the applicable time period for purposes of concurrence by conclusive presumption shall be three months instead of six months.

(d) If the State agency issues a concurrence or is conclusively presumed to concur with the person's new consistency certification, the person will not be required to submit additional consistency certifications and supporting information for State agency review at the time Federal applications are actually filed for the Federal licenses and permits to which such concurrence applies.

(e) Unless the State agency indicates otherwise, copies of Federal license and permit applications for activities described in detail in an amended or new OCS plan which has received State agency concurrence shall be sent by the person to the State agency to allow the State agency to monitor the activities. Confidential and proprietary material within such applications may be deleted.

§ 930.85 Continuing State agency objections.

If the State agency objects to the consistency certification for an amended or new OCS plan, the prohibition in § 930.81 against Federal agency approval of licenses or permits for activities described in detail in such a plan applies, further Secretarial review pursuant to subpart H may take place, and the development of an additional amended or new OCS plan and consistency certification may be required pursuant to §§ 930.83-930.84.

§ 930.86 Failure to comply substantially with an approved OCS plan.

(a) The Department of the Interior and State agencies shall cooperate in their efforts to monitor Federally licensed and permitted activities described in detail OCS plans to make certain that such activities continue to conform to both Federal and State requirements.

(b) If a State agency claims that a person is failing substantially to comply with an approved OCS plan subject to the requirements of this Subpart, and such failure allegedly involves the conduct of activities affecting the coastal zone in a manner that is not consistent with the approved management program, the State agency shall transmit its claim to the U.S. Geological Survey supervisor for the area involved. Such claim shall include: (1) A description of the specific activity involved and the alleged lack of compliance with the OCS plan, and (2) a request for appropriate remedial action. A copy of the claim shall be sent to the person and the Assistant Administrator.

(c) If, after a reasonable time following a request for remedial action, the State agency still maintains that the person is failing to comply substantially with the OCS plan, the governor or section 306(c)(5) State agency (see § 930.18) may file a written objection with the Secretary. If the Secretary finds that the person is failing to comply substantially with the OCS plan, the person shall submit an amended or new OCS plan along with a consistency certification and supporting information to the Secretary of the Interior or designee and to the State agency. Following such a finding by the Secretary, the person shall comply with the originally approved OCS plan, or with interim orders issued jointly by the Secretary and the U.S. Geological Survey, pending approval of the amended or new OCS plan. The directives within §§ 930.83-930.85 shall apply to further State agency review of the consistency certification for the amended or new plan.

(d) A person shall be found to have failed substantially to comply with an approved OCS plan if the State agency claims and the Secretary finds that one or more of the activities described in detail in the OCS plan which affects the coastal zone are being conducted or are having a coastal zone effect substantially different than originally described by the person in the plan or accompanying information and, as a result, the activities are no longer being conducted in a manner consistent with the State's management progam. The Secretary may make a finding that a person has failed substantially to comply with an approved OCS plan only after providing a reasonable opportunity for the person and the Secretary of the Interior to review the State agency's objection and to submit comments for the Secretary's consideration.

Subpart F--Consistency for Federal Assistance to State and Local Governments

§ 930.90 Objectives.

The provisions of this subpart are provided to assure that Federal assistance to State and

local governments for activities affecting the coastal zone is granted only when such activities are consistent with approved coastal zone management programs.

§ 930.91 Federal assistance.

The term "Federal assistance" means assistance provided under a Federal program to an applicant agency through grant or contractual arrangements, loans, subsidies, guarantees, insurance, or other form of financial aid.

§ 930.92 Applicant agency.

The term "applicant agency" means any unit of State or local government, or any related public entity such as a special purpose district, which, following management program approval, submits an application for Federal assistance.

§ 930.93 OMB A-95 process.

The term "OMB A-95 process" describes the project notification and review procedures set forth in the Office of Management and Budget Circular A-95 for the evaluation, review and coordination of Federally assisted programs (41 FR 2052 (1976)).

§ 930.94 Guidance provided by the State agency.

(a) To assist A-95 State and areawide clearing houses, State agencies should include within the management program a listing of specific types of Federal assistance programs subject to a consistency review. Such a listing, and any amendments, will require prior 306(c)(5) state agency (see § 930.18) consultation with affected Federal agencies and approval by the Assistant Administrator.

(b) In the event the State agency chooses to review applications for Federal assistance activities outside of the coastal zone but likely to affect the coastal zone, the State agency must develop a Federal assistance provision within the management program generally describing the geographic area (e.g., coastal floodplains) within which Federal assistance activities will be subject to review. This provision, and any refinements, will require prior 306(c)(5) State agency consultation with affected Federal agencies and approval by the Assistant Administrator.

(c) The State agency shall provide copies of any Federal assistance list or geographic provision, and any refinements, to Federal agencies, units of State or local government empowered to undertake Federally assisted activities within the coastal zone or described geograhphic area, and to the A-95 State and areawide clearinghouses.

§ 930.95 OMB A-95 project notification and review.

(a) Pursuant to the OMB A-95 process, an applicant agency shall notify the appropriate State and areawide clearinghouses of its intent to apply for Federal assistance for an activity located in the coastal zone or the described geographic area.

(b) The applicant agency shall utilize the OMB A-95 process for every major funding phase of the Federal assistance activity which entails the consideration of new information not previously reviewed (e.g., planning and design data not reviewed in earlier project siting phase), or which results in substantial modifications to previously reviewed phases.

(c) The clearinghouse shall ensure that the State agency is afforded an opportunity to review a notification for an activity located in the coastal zone or the described geographic area to determine whether the activity is consistent with the management program.

§ 930.96 Consistency review.

(a) If pursuant to the OMB A-95 process, the State agency does not object to the proposed activity, the Federal agency may grant the Federal assistance to the applicant agency. Notwithstanding State agency consistency approval for the proposed project, the Federal agency may deny assistance to the applicant agency. Federal agencies should not delay processing applications pending receipt of a State agency approval or objection. In the event a Federal agency determines that an application will not be approved, it shall immediately notify the applicant agency and the State agency.

(b) If pursuant to the OMB A-95 process, the State agency objects to the proposed project, the clearinghouse shall notify the applicant agency, Federal agency and the Assistant Administrator of the objection.

(c) State agency objections must describe: (1) how the proposed project is inconsistent with specific elements of the management program, and (2) alternative measures (if they exist) which, if adopted by the applicant agency, would permit the proposed project to be conducted in a manner consistent with the management program.

(d) A State agency objection may be based upon a determination that the applicant agency has failed, following a written State agency request, to supply necessary information. If the State agency objects on the grounds of insufficient information, the objection must describe the nature of the information requested and the necessity of having such information to determine the consistency of the activity with the management program.

(e) State agency objections shall include a statement informing the applicant agency of a

right of appeal to the Secretary on the grounds described in subpart H of this part.

§ 930.97 Federal assisting agency responsibility.

Following receipt of a State agency objection, the Federal agency shall not approve assistance for the activity except as provided in subpart H of this part.

§ 930.98 Federally assisted activities outside of the coastal zone or the described geographic area.

(a) State agencies should monitor proposed Federal assistance activities outside of the coastal zone or the described geographic area (e.g., by use of the OMB A-95 process, review of NEPA environmental impact statements, etc.) and shall immediately notify applicant agencies, Federal agencies, and the appropriate clearinghouse of proposed activities which can reasonably be expected to affect the coastal zone and which the State agency is reviewing for consistency with the management program. Notification shall also be sent by the State agency to the Assistant Administrator. State agencies must inform the clearinghouse and other parties of objections within the time period permitted under the OMB A-95 process, otherwise the State agency waives its right to object to the proposed activity.

(b) If within the permitted time period the State agency notifies the Federal agency of its objection to a proposed Federally assisted activity, the Federal agency shall not provide assistance to the applicant agency except as provided in Subpart H, unless the Assistant Administrator disapproves the State agency's decision to review the activity. The Assistant Administrator shall be guided by the provisions in § 930.54(c) and (d).

§ 930.99 Availability of mediation for Federal assistance disputes.

In the event of a serious disagreement between a Federal and State agency regarding whether a Federal assistance activity is subject to consistency review, either party may request the Secretarial mediation services provided for in Subpart G of this Part. The existence of a serious disagreement will not relieve the Federal agency from the responsibility for withholding Federal assistance for the activity pending satisfaction of the requirements of this subpart, except in cases where the Assistant Administrator has disapproved a State agency decision to review an activity.

§ 930.100 Availability of mediation for previously reviewed activities.

(a) Federal and State agencies shall cooperate in their efforts to monitor Federally assisted activities in order to make certain that such activities continue to conform to both Federal and State requirements.

(b) The State agency shall request that the Federal agency take appropriate remedial action following a serious disagreement resulting from a State agency objection to a Federally assisted activity which was (1) previously determined to be consistent with the State's management program, but which the State agency later maintains is being conducted or is having a coastal zone effect substantially different than originally proposed and, as a result, is no longer consistent with the State management program, or (2) previously determined not to be a project affecting the coastal zone, but which the State agency later maintains is being conducted or is having a coastal zone effect substantially different than originally proposed and, as a result the project affects the coastal zone in a manner inconsistent with the State's management program. The State agency's request must include supporting information and a proposal for recommended remedial action; a copy of the request must be sent to the applicant agency.

(c) If, after a reasonable time following a request for remedial action, the State agency still maintains that a serious disagreement exists with the Federal agency, either party may seek the Secretarial mediation services provided for in Subpart G of this Part.

Subpart G--Secretarial Mediation

§ 930.110 Objectives.

The purpose of this subpart is to describe mediation procedures which Federal and State agencies may use to attempt to resolve serious disagreements which arise during the administration of approved management programs.

§ 930.111 Informal negotiations.

The availability of mediation does not preclude use by the parties of alternative means for resolving their disagreement. In the event a serious disagreement arises, the parties are strongly encouraged to make every effort to resolve the disagreement informally. OCZM shall be available to assist the parties in these efforts.

§ 930.112 Request for mediation.

(a) The Secretary or other head of a Federal agency, or the Governor or the section 306(c)(5) State agency (see § 930.18), may notify the Secretary in writing of the existence of a serious

disagreement, and may request that the Secretary seek to mediate the serious disagreement. A copy of the written request must be sent to the agency with which the requesting agency disagrees, and to the Assistant Administrator.

(b) Within 15 days following receipt of a request for mediation the disagreeing agency shall transmit a written response to the Secretary, and to the agency requesting mediation, indicating whether it wishes to participate in the mediation process. If the disagreeing agency declines the offer to enter into mediation efforts, it must indicate the basis for its refusal in its response. Upon receipt of a refusal to participate in mediation efforts, the Secretary shall seek to persuade the disagreeing agency to reconsider its decision and enter into mediation efforts. If the disagreeing agencies do not all agree to participate, the Secretary will cease efforts to provide mediation assistance.

§ 930.113 Public hearings.

(a) If the parties agree to the mediation process, the Secretary shall appoint a hearing officer who shall schedule a hearing in the local area concerned. The hearing officer shall give the parties at least 30 days notice of the time and place set for the hearing and shall provide timely public notice of the hearing.

(b) At the time public notice is provided, the Federal and State agencies shall provide the public with convenient access to public data and information related to the serious disagreement.

(c) Hearings shall be informal and shall be conducted by the hearing officer with the objective of securing in a timely fashion information related to the disagreement. The Federal and State agencies, as well as other interested parties, may offer information at the hearing subject to the hearing officer's supervision as to the extent and mannner of presentation. Unduly repetitious oral presentation may be excluded at the discretion of the hearing officer; in the event of such exclusion the party may provide the hearing officer with a written submission of the proposed oral presentation. Hearings will be recorded and the hearing officer shall provide transcripts and copies of written information offered at the hearing to the Federal and State agency parties. The public may inspect and copy the transcripts and written information provided to these agencies.

§ 930.114 Secretarial mediation efforts.

(a) Following the close of the hearing, the hearing officer shall transmit the hearing record to the Secretary. Upon receipt of the hearing record, the Secretary shall schedule a mediation conference to be attended by representatives from the Office of the Secretary, the disagreeing Federal and State agencies, and any other interested parties whose participation is deemed necessary by the Secretary. The Secretary shall provide the parties at least 10-days notice of the time and place set for the mediation conference.

(b) Secretarial mediation efforts shall last only so long as the Federal and State agencies agree to participate. The Secretary shall confer with the Executive Office of the President, as necessary, during the mediation process.

§ 930.115 Termination of mediation.

Mediation shall terminate (a) at any time the Federal and State agencies agree to a resolution of the serious disagreement, (b) if one of the agencies withdraws from mediation, (c) in the event the agencies fail to reach a resolution of the serious disagreement within 15 days following Secretarial conference efforts, and the agencies do not agree to extend mediation beyond that period, or (d) for other good cause.

§ 930.116 Judicial review.

The availability of the mediation services provided in this subpart is not intended expressly or implicitly to limit the parties' use of alternate forums to resolve disputes. Specifically, judicial review where otherwise available by law may be sought by any party to a serious disagreement without first having exhausted the mediation process provided for in this subpart.

Subpart H--Secretarial Review Related to the Objectives or Purposes of the Act and National Security Interests

§ 930.120 Objectives.

The provisions of this subpart provide procedures by which the Secretary may find that a Federal license or permit activity, including those described in detail in an OCS plan, or a Federal assistance activity, which is inconsistent with a management program, may be federally approved because the activity is consistent with the objectives or purposes of the Act, or is necessary in the interest of national security.

§ 930.121 Consistent with the objectives or purposes of the Act.

The term "consistent with the objectives or purposes of the Act" describes a Federal license or permit activity, or a Federal assistance activity which, although inconsistent with a State's management program, is found by the Secretary to be permissible because it satisfies the following four requirements:

(a) The activity furthers one or more of the competing national objectives or purposes contained in sections 302 or 303 of the Act.

(b) When performed separately or when its cumulative effects are considered, it will not cause adverse effects on the natural resources of the coastal zone substantial enough to outweigh its contribution to the national interest.

(c) The activity will not violate any requirements of the Clean Air Act, as amended, or the Federal Water Pollution Control Act, as amended, and

(d) There is no reasonable alternative available (e.g., location design, etc.) which would permit the activity to be conducted in a manner consistent with the management program.

§ 930.122 Necessary in the interest of national security.

The term "necessary in the interest of national security" describes a Federal license or permit activity, or a Federal assistance activity which, although inconsistent with a State's management program, is found by the Secretary to be permissible because a national defense or other national security interest would be significantly impaired if the activity were not permitted to go forward as proposed. Secretarial review of national security issues shall be aided by information submitted by the Department of Defense or other interested Federal agencies. The views of such agencies, while not binding, shall be given considerable weight by the Secretary. The Secretary will seek information to determine whether the objected-to activity directly supports national defense or other essential national security objectives.

§ 930.123 Appellant.

The term "appellant" refers to an applicant, person or applicant agency submitting an appeal to the Secretary pursuant to the provisions of this subpart.

§ 930.124 Informal discussions.

In the event the State agency informs the applicant, person or applicant agency that it intends to object to the proposed activity, the parties should consult informally to attempt to resolve the matter in a manner which avoids the necessity of appealing the issue to the Secretary. OCZM shall be available to assist the parties in these discussions.

§ 930.125 Appeals to the Secretary.

(a) An appellant may file a notice of appeal with the Secretary within 30 days of the appellant's receipt of a State agency objection. The notice of appeal shall be accompanied by a statement in support of the appellant's position, along with supporting data and information. The appellant shall send a copy of the notice of appeal and accompanying documents to the Federal and State agencies involved.

(b) No extension of time will be permitted for the filing of a notice of appeal.

(c) The Secretary may approve a reasonable request for an extension of time to submit supporting information so long as the request is filed with the Secretary within the 30-day period. Normally, the Secretary shall limit an extension period to 15 days.

§ 930.126 Federal and State agency responses to appeals.

(a) Upon receipt of the notice of appeal and supporting information, the Federal and State agencies shall have 30 days to submit detailed comments to the Secretary. Copies of such comments shall be sent to the appellant and other agency within the same time period.

(b) Requests for extensions may be made pursuant to § 930.125(c).

§ 930.127 Public notice; receipt of comments.

(a) The Secretary shall provide timely public notice of the appeal within 15 days of receipt of the notice. At a minimum, public notice shall be provided in the immediate area of the coastal zone which is likely to be affected by the proposed activity. At the time public notice is provided, the Federal and State agencies shall provide the public with convenient access to copies of the appellant's notice of appeal and accompanying public information, and to the public information in the agencies' detailed comments.

(b) Interested persons may submit comments to the Secretary within 30 days from the date of public notice, with copies provided to the appellant and to the Federal and State agencies within the same time period.

(c) Requests for extensions may be made pursuant to § 930.125(c).

§ 930.128 Dismissal of appeals.

The Secretary may dismiss an appeal for good cause. Good cause shall include, but is not limited to:

(a) Failure of the appellant to submit a notice of appeal within the required 30-day period;

(b) Failure of the appellant to submit the supporting information within the required period or approved extension period;

(c) Secretarial receipt of a detailed comment from the Federal agency stating that the agency has disapproved the Federal license, permit or assistance application;

(d) Failure of the appellant to base the appeal on grounds that the proposed activity

either (1) is consistent with the objectives or purposes of the Act or (2) is necessary in the interest of national security.

§ 930.129 Public hearings.

The Secretary may order a hearing independently or in response to a request. If a hearing is ordered by the Secretary it shall be guided by the procedures described within § 930.113.

§ 930.130 Secretarial review.

(a) In reviewing an appeal, the Secretary shall find that a proposed Federal license or permit activity, or a Federal assistance activity, is consistent with the objectives or purposes of the Act, or is necessary in the interest of national security, when the information submitted supports this conclusion.

(b) The Secretary shall make all reasonable efforts to complete consideration of an appeal within 90 days from the date of public notice.

(c) Following consideration of the appeal, the Secretary shall issue a decision in writing to the appellant and to the Federal and State agencies indicating whether the proposed activity is consistent with the objectives or purposes of the Act, or is necessary in the interest of national security; the decision shall include the basis for such finding. The Secretary shall provide public notice of the decision.

(d) The decision of the Secretary shall constitute final agency action for the purposes of the Administrative Procedure Act.

§ 930.131 Federal agency responsibility.

(a) If the Secretary finds that the proposed activity is consistent with the objectives or purposes of the Act, or is necessary in the interest of national security, the Federal agency may approve the activitiy.

(b) If the Secretary does not make either of these findings, the Federal agency shall not approve the activity.

§ 930.132 Review initiated by the Secretary.

(a) The Secretary may choose to consider whether a Federal license or permit activity, or a Federal assistance activity, is consistent with the objectives or purposes of the Act, or is necessary in the interest of national security. Secretarial review may be initiated either before or after the completion of State agency review. The Secretary's decision to review the activity may result from an independent concern regarding the activity or a request from interested parties. If the Secretary decides to initiate review, notification shall be sent to the applicant, person or applicant agency, and to the Federal and State agencies. The notice shall include a statement describing the reasons for the review and shall contain a request for submission of detailed comments to be submitted within 30 days from receipt of the notification. Copies of comments shall be exchanged among the parties.

(b) Requests for extensions may be made pursuant to § 930.125(c).

§ 930.133 Public notice; receipt of comments; public hearings.

(a) Upon receipt of detailed comments from the parties, the Secretary shall provide public notice and request public comments in accordance with the provisions in § 930.127.

(b) The Secretary may order a hearing in accordance with the provisions in § 930.129.

§ 930.134 Secretarial review; Federal agency responsibility.

(a) Secretarial review shall be undertaken in accordance with the provisions in § 930.130.

(b) Federal agencies are responsible for adhering to the provisions in § 930.131 when deciding to approve or deny an application for an activity objected to by a State agency and independently reviewed by the Secretary.

Subpart I--Assistant Administrator Reporting and Continuing Review of Federal Actions Subject to the Federal Consistency Requirements

§ 930.140 Objectives.

The provisions of this subpart provide procedures to permit interested parties to notify the Assistant Administrator of Federal actions (a) believed to be inconsistent with an approved management program but which are not so found by the Federal or State reviewing agency, and (b) believed to have been incorrectly determined to be inconsistent with an approved management program. This subpart also provides for the reporting of any Federal actions found by the Assistant Administrator to be inconsistent with an approved management program and for the performance review of State implementation of the Federal consistency provisions of this part.

§ 930.141 Notification of Federal actions believed to be inconsistent with approved management programs.

(a) Interested parties are invited to submit to the Assistant Administrator detailed comments related to the alleged inconsistency of Federal activities including development projects, Federal license or permit activities, including those described in detail in OCS plans, and Federal assistance activities which are subject to the requirements of this part,

and which have not been found by a Federal agency or State agency to be inconsistent with an approved management program. Copies of such comments should be sent to relevant Federal and State agencies, and to the applicant, person or applicant agency as appropriate.

(b) Comments need not conform to any particular form, but should be specific, substantive and factual, and must describe how the Federal action is or would be inconsistent with an approved management program.

(c) Commentators are encouraged to recommend modifications or alternatives to the existing or proposed action which would enable it to be consistent with the management program.

(d) The Assistant Administrator shall assure that public information within such comments is made available for public inspection.

§ 930.142 Notification of Federal actions believed to have been incorrectly determined to be inconsistent with an approved management program.

(a) Interested parties are invited to submit to the Assistant Administrator detailed comments related to Federal license and permit activities, including those described in detail in OCS plans, and Federal assistance activities which are believed to have been incorrectly determined by a State agency to be inconsistent with an approved management program. Copies of such comments should be sent to the relevant Federal and State agencies, and to the applicant, person, or applicant agency as appropriate.

(b) Comments need not conform to any particular form, but should be specific, substantive, and factual, and must clearly describe the basis for the belief that the State agency has incorrectly objected to the Federal action on the grounds of its inconsistency with the management program.

(c) The Asistant Administrator shall assure that public information within such comments is made available for public inspection.

§ 930.143 Assistant Administrator reporting.

After considering the views of interested parties, the relevant Federal agency, State agency, and the applicant, person, or applicant agency, as appropriate, the Assistant Administrator shall determine whether the Federal action will be included in the annual report listing of inconsistent Federal actions.

§ 930.144 Assistant Administrator advisory statements.

Upon request, the Assistant Administrator may issue an advisory statement prior to the issuance of the annual report indicating whether a Federal action will be listed within the annual report as being inconsistent with an approved management program.

§ 930.145 Review of the implementation of Federal consistency provisions.

As part of the responsibility to conduct a continuing review of approved management programs, the Assistant Administrator shall review the performance of each State's implementation of the Federal consistency provisions in this part. The Assistant Administrator shall use information received pursuant to this subpart to evaluate instances where a State agency is believed to have either failed to object to inconsistent Federal actions, or improperly objected to consistent Federal actions. This evaluation shall be incorporated within the Assistant Administrator's general efforts to ascertain instances where a State has not adhered to its approved management program and such lack of adherence is not justified.

H. 18 CFR 270 and 271, Rules Generally Applicable to Regulated Sales of Natural Gas and Ceiling Prices, Title 18 CFR, revised as of April 1, 1980, amended by: 45 FR 28097-98, April 28, 1980; 45 FR 29570, May 5, 1980; 45 FR 49081, July 23, 1980; 45 FR 50557, July 30, 1980; 45 FR 53099, 53114-5, August 11, 1980; 45 FR 56044, August 22, 1980; 45 FR 71564-65, October 29, 1980; 45 FR 71780, October 30, 1980; 45 FR 73027, November 4, 1980; 45 FR 76670, 72, 74, 76, and 81, November 20, 1980; 45 FR 77429, November 24, 1980; 45 FR 80275, December 4, 1980, and 45 FR 84035-36-37, December 22, 1980.

1. Regulations, 18 CFR 270, Rules Generally Applicable to Regulated Sales of Natural Gas, Title 18 CFR, revised as of April 1, 1980; amended by: 45 FR 28097-98, April 28, 1980; 45 FR 49081, July 23, 1980; and 45 FR 53099, 53114, August 11, 1980.

PART 270--RULES GENERALLY APPLICABLE TO REGULATED SALES OF NATURAL GAS

Subpart A--General Rules and Definitions

AUTHORITY: Natural Gas Policy Act of 1978, P.L. 95-621, 92 Stat. 3350, unless otherwise noted.

SOURCE: 43 FR 56544, Dec. 1, 1978, unless otherwise noted.

Subpart A--General Rules and Definitions

§ 270.101 Application of ceiling prices to first sales of natural gas.

(a) Maximum lawful price. It is unlawful for any person to sell natural gas (other than deregulated high-cost gas) at a first sale price in excess of the highest maximum lawful price applicable to such gas under Part 271. No maximum lawful price applies to deregulated high-cost gas.

(b) Effect of maximum lawful price on contract price. If the price established under a contract for the first sale of natural gas does not exceed the applicable maximum lawful price, then such maximum lawful price does not supersede or nullify the effectiveness of the price established under such contract.

(c) Maximum lawful prices requiring jurisdictional agency determinations. Except to the extent that a seller is authorized to make interim collection under Part 273:

(1) Any maximum lawful price under any of the following subparts of Part 271 applies to a first sale of natural gas only if a determination by a jurisdictional agency that such gas qualifies under such subpart has become final in accordance with Parts 274 and 275:

(i) Subpart B (relating to new natural gas and certain OCS gas);

(ii) Subpart C (relating to new, onshore production well);

(iii) Subpart G (relating to high-cost natural gas); and

(iv) Subpart H (relating to stripper well natural gas).

(2) The price of gas is deregulated only if a determinatin by a jurisdictional agency that such gas qualifies under Part 272 has become final in accordance with Parts 274 and 275.

(d) Other categories of natural gas. (1) Certain committed or dedicated natural gas. The maximum lawful prices under Subpart D of Part 271 (relating to certain committed or dedicated natural gas) apply to a first sale to the extent provided in such subpart, if the applicable filing requirements under §§ 154.92 and 154.94 of this chapter are met.

(2) Existing intrastate contracts; intrastate rollover contracts; certain other categories. The maximum lawful prices under Subparts E, F, and I of Part 271 (relating to existing intrastate contracts, intrastate rollover contracts, and certain other categories of natural gas) apply to first sales of natural gas without requirement of a prior determination by the Commission or a jurisdictional agency.

(e) General refund obligation. Any price collected with respect to a first sale of natural gas to which this subchapter applies is collected subject to a general obligation promptly to refund any portion of such price, together with interest determined in accordance with § 154.102(d), which is in excess of the maximum lawful price, or collection of which is not authorized by this subchapter. Compliance with the specific refund requirements of § 273.302 shall not terminate the general refund obligation under this subchapter.

[43 FR 56544, Dec. 1, 1978, as amended at 44 FR 48661, Aug. 20, 1979; 44 FR 53505, Sept. 14, 1979; 45 FR 28097, Apr. 28, 1980]

§ 270.102 Definitions.

(a) NGPA definitions. Terms defined in the NGPA shall have the same meaning for purposes of this subchapter as they have under the NGPA, unless further defined in this subchapter.

(b) Subchapter H definitions. For purposes of this subchapter:

(1) "NGPA" means the Natural Gas Policy Act of 1978.

(2) "British thermal unit" or "Btu" means the quantity of heat required to raise the temperature of one pound avoirdupois of pure water from 58.5 degrees to 59.5 degrees Fahrenheit, determined in accordance with § 270.204.

(3) "MMBtu" means million British thermal units.

(4)(i) Except as provided in clause (ii), "production in commercial quantities" means production of natural gas from a well or reservoir which is either: (A) sold and delivered to one other than the operator; or (B) (subject to § 271.204(e)) retained by the operator, or any owner of the production as severance, for beneficial economic use.

(ii) Natural gas used for the testing of natural gas wells or for other field uses which are production related shall not be considered produced in commercial quantities.

(iii) Any of the following information may be considered as evidence of sale and delivery, or production for the operator's or other owner's beneficial economic use.

(A) payment of severance taxes;

(B) payment of royalties;

(C) production reports filed with a jurisdictional agency;

(D) sales contract together with verification by a purchaser that natural gas had been delivered and paid for under the contract; or

(E) any other substantial evidence that production has been sold and delivered or retained for the beneficial use of the operator or other owner of production at severance.

(5) "Crude oil" means a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities.

(6) "Surface location" means the point on the Earth's surface from which drilling of a well is commenced except that in the case of a well drilled in permanent surface waters, "the Earth's surface" means the mean elevation of the surface of the water.

(7) "OCS" means the Outer Continental Shelf as defined in section 2 (35) of the NGPA.

(8) "Existing intrastate contract" means any intrastate contract for the first sale of natural gas in existence on November 8, 1978. A contract is in existence on November 8, 1978 if on that date, there is a promise or a set of promises for the breach of which the law gives a remedy, or the performance of which the law in some way recognizes as a duty. For the purposes of this subchapter "existing intrastate contract" includes a "successor to an existing intrastate contract."

(9) "Successor to an existing intrastate contract" means any contract, other than a rollover contract, entered into on or after November 9, 1978, for the first sale of natural gas which was previously subject to an existing intrastate contract, whether or not there is an identity of parties or terms with those of such existing intrastate contract. The term "successor to an existing intrastate contract" includes a contract the primary term of which has not expired but which has been assigned to a different party in interest.

(10) "Intrastate contract" means any contract applicable to the sale of natural gas which was not committed or dedicated to interstate commerce on November 8, 1978.

(11) "Intrastate rollover contract" means any contract, entered into on or after November 9, 1978, for the first sale of natural gas that was previously subject to an existing intrastate contract which expired at the end of a fixed term (not including any extension thereof taking effect on or after November 9, 1978), specified by the provisions of such existing contract, as such contract was in effect on November 9, 1978, whether or not there is an identity of parties or terms with those of such existing contract.

(12) "Jurisdictional agency" means the state or federal agency identified in Subpart E of Part 274.

(13) "New well" means any well--

(i) The surface drilling of which began on or after February 19, 1977; or

(ii) The depth of which was increased, by means of drilling on or after February 19, 1977, to a completion location which is located at least 1,000 feet below:

(A) The depth of the deepest completion location of such well attained before February 19, 1977, if such well had a completion location; or

(B) If such well had no completion location because it was a dry hole the drilling of which was terminated prior to February 19, 1977, the deepest drilled depth attained in such dry hole.

(14) For the definition of "deregulated high-cost gas," see § 272.103(a).

(15) "Production costs" means all cost incurred for exploration, development, production, and abandonment operations, enhanced recovery techniques (including costs of compression incurred in the production of stripper well natural gas to which the pricing provisions of Subpart H of Part 271 apply), gas-lift pumping or other liquid lifting equipment located on or

in the vicinity of the wellhead or the point of commingling gas on the offshore platform from which the gas is produced, and costs that attend compression necessary for lifting liquids, cycling gas in a gas-condensate reservoir or pressurizing an oil reservoir.

(16) "Non-allocable costs" means all costs incurred for the construction or operation of facilities to recover, separate, extract, process, treat, dehydrate, store, or transport crude oil or natural gas liquids or both.

(17) "Production-related costs" means costs (excluding production costs and non-allocable costs) of compressing, gathering, processing, treating, liquefaction, conditioning, or transporting natural gas, or other similar costs.

(Natural Gas Act, as amended, 15 U.S.C. 717, et seq.: Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, et seq., Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301-3432, Department of Energy Organization Act, Pub. L. 95-91, 42 U.S.C. 7107, et seq., E.O. 12009, 42 FR 46267)

[43 FR 56544, Dec. 1, 1978, as amended at 44 FR 34474, June 15, 1979; 44 FR 53493, Sept. 14, 1979; Order 68, 45 FR 5684, Jan. 24, 1980; 45 FR 28098, Apr. 28, 1980; 45 FR 53114, Aug. 11, 1980]

§ 270.103 Effective date.

The provisions of this subchapter apply to deliveries of natural gas on or after December 1, 1978.

Subpart B--Special Rules

§ 270.201 [Reserved]

[45 FR 49081, July 23, 1980]

§ 270.202 Resales.

(a) General rule. In the case of any first sale of natural gas which is a resale of such gas, the maximum lawful price shall be the higher of:

(1) the maximum lawful price which would be applicable to such sale if it were not a resale; or

(2) The maximum lawful price applicable to the natural gas sold to the reseller. In the case of natural gas which when sold to the reseller was subject to more than one maximum lawful price, the reseller may determine the maximum lawful price for purposes of this subparagraph on the basis of the average of the maximum lawful prices applicable to the natural gas sold to the reseller (weighted according to the number of purchased Btu's that are subject to each different maximum lawful price).

(b) Special rule for interim collections.

(1) If the price for a first sale to a reseller is charged and collected under the authority of Part 273 (relating to interim collection), then:

(i) the price authorized to be collected under Part 273 shall be treated as a maximum lawful price for purposes of paragraph (a)(2) of this section; and

(ii) the price charged and collected by the reseller shall be subject to the same refund conditions under Part 273 as are imposed on the person who sold the natural gas to the reseller.

(2) The reseller is not obligated by Part 273 to make any filings with the Commission if such filings have been made by:

(i) The person who sold the natural gas to the reseller; or

(ii) A person designated under § 273.103(b) by the person in clause (i) of this subparagraph to make such filings.

(c) Allowances. A resale of natural gas shall not be considered to exceed any maximum lawful price established in paragraph (a) of this section if it exceeds such price to the extent necessary to recover state severance taxes or production-related costs which are borne by the reseller and if such recovery by the reseller is allowed under Subpart K of Part 271.

(2) If a price for a first sale to a reseller of natural gas is not considered to exceed the applicable maximum lawful price applicable to such sale by reason of an amount allowed under Subpart K, then for purposes of applying paragraph (a)(2) of this section the maximum lawful price applicable to the natural gas sold to the reseller shall be considered to be increased by the amount so allowed.

(d) Adjustments. Pursuant to section 502(c) of the NGPA and § 1.41 of this chapter, a reseller may apply to the Commission for an adjustment of the maximum lawful price in paragraph (a) of this section on the grounds that such price results in special hardship, inequity or an unfair distribution of burdens.

(e) Definition. For purposes of this section: (1) "Resale" of natural gas means the sale of natural gas, all or a portion of which was both purchased and resold in transactions that are first sales as defined in the NGPA.

(2) A "reseller" means the seller in a resale of such natural gas.

(3) "Percentage-of-proceeds sale" means a sale of natural gas the price for which is computed as a percentage of the proceeds from the resale of natural gas attributable to such sale.

(f) Record retention. In addition to any records required to be retained by reason of an election made by the reseller under § 270.101 (b), such reseller shall maintain such records as are sufficient to demonstrate that prices charged for the resale of natural gas do not exceed the maximum lawful prices prescribed in

this section. Such records shall include:

(1) a record of each resale of natural gas by the reseller, including the identify of the purchaser and the volume and price of such sale;

(2) a record of each sale of natural gas to the reseller which has been sold in a resale by such reseller including the volume and price of such sale;

(3) a copy of the contracts covering the purchase and resale of natural gas; and

(4) a record of the method by which the reseller computes the maximum lawful price applicable to each resale and the documents relied on to make the computations.

(g) Period for keeping records. Each reseller required to maintain records under this section shall maintain and preserve contracts for any sale to which this section applies for at least three years after the expiration date of such contracts and such other records for at least three years after the date of the relevant transaction or event.

(h) Special rules for percentage-of-proceeds sales. In the case of natural gas purchased by a reseller in a percentage-of-proceeds sale, the reseller may determine the maximum lawful price for the resale under paragraph (a)(1) of this section. If the reseller so determines his maximum lawful price, any sale to such reseller in such percentage of proceeds sale shall not be treated as a first sale for purpose of this subchapter (other than Part 276).

(Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Department of Energy Organization Act, 42 U.S.C. 7107-7352; E.O. 12009, 42 FR 42267; Natural Gas Policy Act of 1978; 15 U.S.C. 3301-3432)

[43 FR 56544, Dec. 1, 1978; 43 FR 59482, Dec. 21, 1978, as amended by Order 68, 45 FR 5684, Jan. 24, 1980; 45 FR 49081, July 23, 1980]

§ 270.203 Pipeline, distributor and affiliate production.

(a) Attribution rule for pipelines and distributors. For purposes of applying section 2 (21)(B) of the NGPA, a sale by a pipeline or distributor is a sale of natural gas attributable to volumes of natural gas produced by such pipeline or distributor to the extent that such sale is comprised exclusively of production volumes of natural gas from identifiable wells, properties, or reservoirs which are owned by such pipeline or distributor.

(b) Circumvention rule for pipelines and distributors. In order to prevent circumvention of the maximum lawful prices established under Title I of the NGPA, the term, "first sale" includes any sale by a pipeline or distributor which is comprised of production volumes from identifiable wells, properties, or reservoirs if a portion of those volumes is produced from wells, properties, or reservoirs owned by such pipeline or distributor unless:

(1) the price at which such natural gas is sold is regulated pursuant to the Natural Gas Act or is regulated by a State agency empowered by State statute to establish, modify or set aside the rate for such sale; or

(2) The Commission, on application, has determined not to treat such sale as a first sale.

(c) Sales by certain affiliates. Any sale by an affiliate of a pipeline or distributor is a first sale if such affiliate is not itself a pipeline or distributor, unless the Commission, on application, has determined not to treat such sale as a first sale. For purposes of this paragraph, the term "sale" does not include any transaction between an interstate pipeline and an affiliate thereof if such transaction would not have been treated as a sale for purposes of the Natural Gas Act.

(d) Reports. A pipeline, distributor or affiliate thereof must file a report with this Commission every 6 months showing the price charged in a sale which was excluded from first sale treatment under paragraph (b)(2) or (c) of this section. Any determination under paragraph (b)(2) or (c) may be revoked by the Commission on the basis of information in such reports or on the basis of other information.

(e) Definitions. For the purposes of this section:

(1) "Pipeline or distributor" means an interstate pipeline, an intrastate pipeline, or a local distribution company.

(2) "State agency" means a State, a political subdivision of a State, or an agency or instrumentality of either.

(f) Cross reference. For treatment of interstate pipeline and affiliate production delivered to a pipeline other than in a first sale, see § 2.66 and § 154.42 of this chapter.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 et seq.; Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Department of Energy Organization Act, 42 U.S.C. 7107 et seq.; E.O. 12009, 42 FR 46267)

[Order 58, 44 FR 66580, Nov. 20, 1979; 45 FR 53099, Aug. 11, 1980]

§ 270.204 Btu content per cubic foot of natural gas.

(a) Measurement. The Btu content of one cubic foot of natural gas under the standard conditions specified in paragraph (b) of this section is the number of Btu's produced by the complete combustion of such cubic foot of gas, at constant pressure with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air and when the water form-

ed by such combustion is condensed to a liquid state.

(b) Standard conditions. The standard conditions for purposes of paragraph (a) of this section are as follows: The gas is saturated with water vapor at 60 degrees Fahrenheit under a pressure equivalent to that of 30.00 inches of mercury at 32 degrees Fahrenheit, under standard gravitational force (980.665 centimeters per second squared).

[45 FR 49081, July 23, 1980]

§ 270.205 Contractual authorization to collect NGPA rates.

(a) Existing interstate contracts. In the case of an existing contract for a first sale of natural gas to which the Natural Gas Act applies:

(1) Any contractual provision for a change in price in such contract which by its terms specifically permits collection of NGPA rates or of maximum lawful prices prescribed by legislation, constitutes contractual authorization to charge and collect the NGPA rates applicable to such first sale.

(2) A contractual provision described in § 154.93 (b-1) (relating to area rate clauses), or similar provision, generally will be considered to constitute contractual authorization to charge and collect an NGPA rate to the extent the parties intended to authorize charging and collection of one or more NGPA rates under the contract.

(b) Existing intrastate contracts. In the case of an existing contract (other than a contract to which paragraph (a) applies):

(1) Except as provided in paragraph (b)(2) of this section, any contractual provision for a change in price may operate according to the terms of such provision except that such provision is not operative to authorize a seller to charge and collect an amount in excess of the highest applicable NGPA rate.

(2) If natural gas sold under such contract is subject to section 105(b)(1) of the NGPA and qualifies for no higher maximum lawful price, no contractual provision for a change in the price under such contract may operate to permit a price under the contract in excess of the new natural gas price under section 102 of the NGPA.

(c) Modification of contracts. The NGPA does not prohibit the parties to contract for the first sale of natural gas from amending or modifying such contract to permit the seller to charge and collect any applicable NGPA rate. If natural gas sold under such contract is subject to section 105(b)(1) of the NGPA and qualifies for no higher maximum lawful price under any other provision of the NGPA, no amendment or modification of such contract may provide authorization for seller to charge and collect a price which exceeds the price under the terms of the contract as in effect on November 9, 1978.

(d) Definition. For purposes of this section, "NGPA rate" means maximum lawful price prescribed by or under the NGPA (including any price collection of which is authorized by Part 273) of this chapter.

(Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Natural Gas Policy Act of 1978; Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301-3432, Department of Energy Organization Act, Pub. L. 95-91, 47 U.S.C. 7101-7352, E.O. 12009, 42 FR 46267)

[44 FR 16908, Mar. 30, 1979, as amended by Order 23-A, 44 FR 34473, June 15, 1979; Order 68, 45 FR 5684, Jan. 24, 1980]

§ 270.206 Applicability of section 314 "Limitation on Effectiveness of Comminling and Simmilar Clauses".

For the purposes of section 314(a) of the NGPA, (relating to unenforceability of commingling and similar clauses) the term "natural gas covered by this Act" means natural gas which is described in any one or more of the following paragraphs:

(a) Natural gas which is not committed or dedicated to interstate commerce as of November 8, 1978.

(b) Natural gas, the sale in interstate commerce of which (1) is authorized under NGPA section 302(a) or 311(b); or (2) is pursuant to an assignment under NGPA section 312(a).

(c) Natural gas, the transportation in interstate commerce of which is (1) pursuant to any order under NGPA section 302(c) or NGPA section 303(b), (c), (d), or (h); or (2) authorized by the Commission under NGPA section 311(a).

[44 FR 18967, Mar. 30, 1979]

§ 270.207 Sales of volumes of gas which include deregulated high-cost gas.

No portion of the price paid for the first sale of deregulated high-cost gas, as defined in § 272.103, or gas for which an application that the gas qualifies as deregulated high-cost gas is pending, may represent consideration for the sale of natural gas which is not deregulated high-cost gas.

[45 FR 28098, Apr. 28, 1980]

2. Regulations, 18 CFR 271, Ceiling Prices, Title 18 CFR, revised as of April 1, 1980; amended by: 45 FR 28098, April 28, 1980; 45 FR 29570, May 5, 1980; 45 FR 50557, July 30, 1980; 45 FR 53115, August 11, 1980; 45 FR 56044, August 22, 1980; 45 FR 71564, October 29, 1980; 45 FR 71780, October 30, 1980; 45 FR 73027, November 4, 1980; 45 FR 76670, 72, 74, 76, 81, November 20, 1980; 45 FR 77429, November 24, 1980; 45 FR 80275, December 4, 1980; and 45 FR 84035, December 22, 1980.

PART 271—CEILING PRICES

AUTHORITY: Natural Gas Policy Act of 1978, P.L. 95-621, 92 Stat. 3350, unless otherwise noted.

SOURCE: 43 FR 56551, Dec. 1, 1978, unless otherwise noted.

Subpart A--Summary Tables and Calculations

§ 271.101 Ceiling prices for certain categories of natural gas.

(a) The maximum lawful price for natural gas subject to Subparts B, C, G, H, and I of this part, and certain natural gas subject to Subpart F thereof, are specified in Table I. The maximum lawful prices for certain categories of natural gas subject to Subpart D of this part are specified in Table II.

TABLE I - Natural Gas Ceiling Prices

(other than NGPA §§ 104 and 106(a))
Maximum lawful price per MMBtu for deliveries in:

Subpart of Part 271	NGPA Section	Category of Gas	Dec. 1978	Jan. 1979	Feb. 1979	Mar. 1979	Apr. 1979	May 1979	June 1979
B	102	New, Natural Gas, Certain OCS Gas	$2.078	$2.096	$2.116	$2.136	$2.156	$2.177	$2.198
C	103	New, Onshore Production Wells	1.969	1.980	1.993	2.006	2.019	2.033	2.047
F	106(b)(1)(B)	Alternative Maximum Lawful Price for Certain Intrastate Rollover Gas 1/	1.121	1.128	1.136	1.144	1.152	1.160	1.168
G	107(c)(1)	High-Cost Gas (deep gas) 2/	2.078	2.096	2.116	2.136	2.156	2.177	2.198
	107(c)(5)	Gas Produced from Tight Formations 3/	.....	.....	.....	.....	.....	.....	.....
H	108	Stripper Gas	2.224	2.243	2.264	2.285	2.306	2.329	2.352
I	109	Not Otherwise Covered	1.630	1.639	1.650	1.661	1.672	1.684	1.696

1/ Section 271.602(a) provides that for certain gas sold under an intrastate rollover contract the maximum lawful price is the higher of the price paid under the expired contract, adjusted for inflation or an alternative Maximum Lawful Price specified in this Table. This alternative Maximum Lawful Price for each month appears in this row of Table 1.

2/ Commencing November 1, 1979, the price of natural gas finally determined to be eligible as deep high-cost gas under section 107(c)(1) of the NGPA is deregulated. (See, Part 272 of the Commission's Regulations.) Prior to that date, the maximum lawful price applicable to deep high-cost gas was the price specified in Subpart B of Part 271.

3/ The maximum lawful price for tight formation gas is the lesser of the negotiated contract price or 200% of the price specified in Subpart C of Part 271. The maximum lawful price for tight formation gas applies on or after July 16, 1979. (See, § 271.703 and § 273.204.)

TABLE I - Natural Gas Ceiling Prices
(Continued)

(other than NGPA §§ 104 and 106(a))
Maximum lawful price per MMBtu for deliveries in:

Subpart of Part 271	NGPA Section	Category of Gas	July 1979	Aug. 1979	Sept. 1979	Oct. 1979	Nov. 1979	Dec. 1979	Jan. 1980
B	102	New, Natural Gas, Certain OCS Gas	$2.220	$2.244	$2.268	$2.292	$2.314	$2.336	$2.358
C	103	New, Onshore Production Wells	2.062	2.079	2.096	2.113	2.128	2.143	2.158
F	106(b)(1)(B)	Alternative Maximum Lawful Price for Certain Intrastate Rollover Gas 1/	1.176	1.185	1.195	1.205	1.213	1.221	1.229
G	107(c)(1)	High-Cost Gas (deep gas) 2/	2.220	2.244	2.268	2.292	.....	.....	.....
	107(c)(5)	Gas Produced from Tight Formations 3/	4.124	4.158	4.192	4.226	4.256	4.286	4.316
H	108	Stripper Gas	2.375	2.400	2.426	2.452	2.478	2.499	2.523
I	109	Not Otherwise Covered	1.708	1.722	1.736	1.750	1.762	1.774	1.786

TABLE I - Natural Gas Ceiling Prices
(Continued)

(other than NGPA §§ 104 and 106(a))
Maximum lawful price per MMBtu for deliveries in:

Subpart of Part 271	NGPA Section	Category of Gas	Feb. 1980	Mar. 1980	Apr. 1980	May 1980	June 1980	July 1980	Aug. 1980
B	102	New, Natural Gas, Certain OCS Gas	$2.381	$2.404	$2.428	$2.453	$2.478	$2.504	$2.532
C	103	New, Onshore Production Wells	2.173	2.188	2.204	2.221	2.238	2.255	2.274
F	106(b)(1)(B)	Alternative Maximum Lawful Price for Certain Intrastate Rollover Gas 1/	1.238	1.247	1.256	1.266	1.276	1.286	1.297

TABLE I - Natural Gas Ceiling Prices
(Continued)

(other than NGPA §§ 104 and 106(a))
Maximum lawful price per MMBtu for deliveries in:

Subpart of Part 271	NGPA Section	Category of Gas	Feb. 1980	Mar. 1980	Apr. 1980	May 1980	June 1980	July 1980	Aug. 1980
G	107(c)(1)	High-Cost Gas (deep gas) 2/	.....	.....	.....	.....	.....	.....	.....
	107(c)(5)	Gas Produced from Tight Formations 3/	4.346	4.376	4.408	4.442	4.476	4.510	4.548
H	108	Stripper Gas	2.548	2.573	2.598	2.625	2.652	2.680	2.710
I	109	Not Otherwise Covered	1.799	1.812	1.825	1.839	1.853	1.867	1.883

TABLE I - Natural Gas Ceiling Prices
(Continued)

(other than NGPA §§ 104 and 106(a))
Maximum lawful price per MMBtu for deliveries in:

Subpart of Part 271	NGPA Section	Category of Gas	Sept. 1980	Oct. 1980	Nov. 1980	Dec. 1980	Jan. 1981
B	102	New, Natural Gas, Certain OCS Gas	$2.560	$2.588	$2.614	$2.640	$2.667
C	103	New, Onshore Production Wells	2.293	2.312	2.329	2.346	2.363
F	106(b)(1)(B)	Alternative Maximum Lawful Price for Certain Intrastate Rollover Gas 1/	1.308	1.319	1.329	1.339	1.349
G	107(c)(1)	High-Cost Gas (deep gas) 2/	.....	.....	.....	.....	.....
	107(c)(5)	Gas Produced from Tight Formations 3/	4.586	4.624	4.658	4.692	4.726
H	108	Stripper Gas	2.740	2.770	2.798	2.826	2.855
I	109	Not Otherwise Covered	1.899	1.915	1.929	1.943	1.957

TABLE II
Natural Gas Ceiling Prices: NGPA §§ 104 and 106(a) (Subpart D, Part 271)

Category of Natural Gas	Type of Sale or Contract	Maximum lawful price per MMBtu for deliveries made in: Dec. 1978	Jan. 1979	Feb. 1979	Mar. 1979	Apr. 1979	May 1979	June 1979	July 1979
Post-1974 gas	All producers	$1.630	$1.639	$1.650	$1.661	$1.672	$1.684	$1.696	$1.708
1973-1974 Biennium gas	Small producer	1.379	1.387	1.396	1.405	1.414	1.424	1.434	1.444
	Large producer	1.058	1.064	1.071	1.078	1.085	1.093	1.101	1.109
Interstate Rollover gas[1]	Small producer	.702	.715	.715	.715	.715	.715	.715	.715
	Large producer	.603	.607	.611	.615	.619	.623	.627	.631
Replacement contract gas or recompletion gas	Small producer	.771	.775	.780	.785	.790	.796	.802	.808
	Large producer	.593	.596	.600	.604	.608	.612	.616	.620
Flowing gas	Small producer	.393	.395	.398	.401	.404	.407	.410	.413
	Large producer	.332	.334	.336	.338	.340	.342	.344	.346
Certain Permian Basin gas	Small producer	.462	.465	.468	.471	.474	.477	.480	.486
	Large producer	.405	.407	.410	.413	.416	.419	.422	.425
Certain Rocky Mountain gas	Small producer	.462	.465	.468	.471	.474	.477	.480	.483
	Large producer	.393	.395	.398	.401	.404	.407	.410	.413
Certain Appalachian Basin gas	North subarea contracts dated after 10-7-69	.368	.370	.372	.374	.376	.379	.382	.385
	Other Contracts	.344	.346	.348	.350	.352	.355	.358	.361
Minimum Rate gas[2]	All producers	.203	.204	.205	.206	.207	.208	.209	.210

[1]The price for interstate rollover gas is the higher of the price listed in this table or the just and reasonable price under the expired contract as adjusted for inflation (See §271.402 (c)(3)).

[2]Prices for minimum rate gas are expressed in terms of dollars per MCF, rather than per MMBtu.

TABLE II--(Continued)

Category of Natural Gas	Type of Sale or Contract	Maximum lawful price per MMBtu for deliveries made in: Aug. 1979	Sept. 1979	Oct. 1979	Nov. 1979	Dec. 1979	Jan. 1980	Feb. 1980	Mar. 1980
Post-1974 gas	All producers	$1.722	$1.736	$1.750	$1.762	$1.774	$1.786	$1.799	$1.812
1973-1974 Biennium gas	Small producer	1.456	1.468	1.480	1.490	1.500	1.510	1.521	1.532
	Large producer	1.118	1.127	1.136	1.144	1.152	1.160	1.168	1.176
Interstate Rollover gas[1]	Small producer	.715	.715	.715	.715	.715	.728	.728	.728
	Large producer	.636	.641	.646	.650	.654	.659	.664	.669
Replacement contract gas or recompletion gas	Small producer	.815	.822	.829	.835	.841	.847	.853	.859
	Large producer	.625	.630	.635	.639	.643	.647	.652	.657
Flowing gas	Small producer	.416	.419	.422	.425	.428	.431	.434	.437
	Large producer	.349	.352	.355	.357	.359	.361	.364	.367
Certain Permian Basin gas	Small producer	.487	.491	.495	.498	.501	.504	.508	.512
	Large producer	.428	.431	.434	.437	.440	.443	.446	.449
Certain Rocky Mountain gas	Small producer	.487	.491	.495	.498	.501	.504	.508	.512
	Large producer	.416	.419	.422	.425	.428	.431	.434	.437
Certain Appalachian Basin gas	North subarea contracts dated after 10-7-69	.388	.391	.394	.397	.400	.403	.406	.409
	Other Contracts	.364	.367	.370	.373	.376	.379	.382	.385
Minimum Rate gas[2]	All Producers	.212	.214	.216	.217	.218	.220	.222	.224

TABLE II--(Continued)

Category of Natural Gas	Type of Sale or Contract	Maximum lawful price per MMBtu for deliveries made in: Apr. 1980	May 1980	June 1980	July 1980	Aug. 1980
Post-1974 gas	All Producers	$1.825	$1.839	$1.853	$1.867	$1.883
1973-1974 Biennium gas	Small producer	1.543	1.555	1.567	1.579	1.592
	Large producer	1.184	1.193	1.202	1.211	1.221
Interstate Rollover gas[1]	Small producer	.728	.728	.728	.728	.728
	Large producer	.674	.679	.684	.689	.695
Replacement contract gas or recompletion gas	Small producer	.865	.872	.879	.886	.893
	Large producer	.662	.667	.672	.677	.683
Flowing gas	Small producer	.440	.443	.446	.449	.453
	Large producer	.370	.373	.376	.379	.382
Certain Permian Basin gas	Small producer	.516	.520	.524	.528	.532
	Large producer	.452	.455	.459	.463	.467
Certain Rocky Mountain gas	Small producer	.516	.520	.524	.528	.532
	Large producer	.440	.443	.446	.449	.453
Certain Appalachian Basin gas	North subarea contracts dated after 10-7-69	.412	.415	.418	.421	.425
	Other Contracts	.388	.391	.394	.397	.400
Minimum Rate gas[2]	All Producers	.226	.228	.230	.232	.234

TABLE II--(Continued)

Category of Natural Gas	Type of Sale or Contract	Maximum lawful price per MMBtu for deliveries made in: Sept. 1980	Oct. 1980	Nov. 1980	Dec. 1980	Jan. 1981
Post-1974 gas	All producers	$1.899	$1.915	$1.929	$1.943	$1.957
1973-1974 Biennium gas	Small producer	1.605	1.619	1.631	1.643	1.655
	Large producer	1.231	1.241	1.250	1.259	1.268
Interstate Rollover gas[1]	Small producer	.728	.728	.728	.728	.741
	Large producer	.701	.707	.712	.717	.722
Replacement contract gas or recompletion gas	Small producer	.901	.909	.916	.923	.930
	Large producer	.689	.695	.700	.705	.710
Flowing gas	Small producer	.457	.461	.464	.467	.470
	Large producer	.385	.388	.391	.394	.397
Certain Permian Basin gas	Small producer	.536	.541	.545	.549	.553
	Large producer	.471	.475	.479	.483	.487
Certain Rocky Mountain gas	Small producer	.536	.541	.545	.549	.553
	Large producer	.457	.461	.464	.467	.470
Certain Appalachian Basin gas	North subarea contracts dated after 10-7-69	.429	.433	.436	.439	.442
	Other Contracts	.403	.406	.409	.412	.415
Minimum Rate gas[2]	All Producers	.236	.238	.240	.242	.244

(b) Caveat. The tables in paragraph (a) of this section are summaries of applicable maximum lawful prices and may not be relied upon to establish qualification for a particular price. The seller should examine the other provisions of this subchapter in order to ascertain whether the natural gas in question qualifies for the price appearing in the table or some other price.

(c) Cross reference. For maximum lawful prices applicable to natural gas sold under existing intrastate contracts or intrastate rollover contracts, see Part 271, Subparts E and F.

(Natural Gas Act, as amended, (15 U.S.C. 717 et seq.), Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Energy Supply and Environmental Coordination Act, (15 U.S.C. 791, et seq.), Federal Energy Administration Act, (15 U.S.C. 761, et seq.), Department of Energy Organization Act, (42 U.S.C. 7107 et seq.), Pub. L. 95-91, E.O. 12009, 42 F.R. 46267))

[43 FR 56551, Dec. 1, 1978, as amended at 44 FR 48661, Aug. 20, 1979; 45 FR 7782, Feb. 5, 1980; 45 FR 16173, Mar. 13, 1980; 45 FR 29570, May 5, 1980; 45 FR 50557, July 30, 1980; 45 FR 73027, Nov. 4, 1980]

§ 271.102 Calculation of inflation adjustment for certain maximum lawful prices.

(a) Maximum lawful prices for first sales of certain categories of natural gas to which Subparts D, E, and F apply are to be calculated in the following manner:

(1) Determine the base price applicable for the base month.

(2) For the month following the base month, multiply the inflation adjustment applicable for such following month by the base price.

(3) For each succeeding month (through the month of delivery), multiply the inflation adjustment applicable for such succeeding month by the price calculated under this paragraph for the prior month.

(b) The price determined for each month under paragraph (a) shall be rounded to the nearest mill (rounding to the next highest mill only that fraction which is one-half a mill or greater).

(c) Inflation adjustment. The inflation adjustment applicable to each month, beginning with May 1977, and ending with the last month of the present quarter, is specified in the following table:

TABLE III--Inflation Adjustment

Month of Delivery	Factor by which price in preceding month is multiplied.
1977	
May	1.00636
June	1.00636
July	1.00431
August	1.00431
September	1.00431
October	1.00463
November	1.00463
December	1.00463
1978	
January	1.00597
February	1.00597
March	1.00597
April	1.00889
May	1.00889
June	1.00889
July	1.00581
August	1.00581
September	1.00581
October	1.00581
November	1.00581
December	1.00581
1979	
January	1.00581
February	1.00667
March	1.00667
April	1.00667
May	1.00713
June	1.00713
July	1.00713
August	1.00805
September	1.00805
October	1.00805
November	1.00690
December	1.00690
1980	
January	1.00690
February	1.00713
March	1.00713
April	1.00713
May	1.00774
June	1.00774
July	1.00774
August	1.00843
September	1.00843
October	1.00843
November	1.00744
December	1.00744
1981	
January	1.00744

(d) Definitions. For purposes of this section: (1) "base price" means:

(i) for maximum lawful prices to be calculated under § 271.402(c)(1) (relating to certain committed or dedicatd gas), the just and reasonable rate for April 20, 1977;

(ii) for maximum lawful prices to be calculated under § 271.502(b)(2) (relating to certain existing intrastate contracts), the contract price per MMBtu on November 9, 1978; and

(iii) for maximum lawful prices to be calculated under § 271.602(a)(1) (relating to certain rollover contracts), the contract price per MMBtu under the expired contract for the month in which the effective date of the rollover contract occurs.

(2) "base month" means:

(i) April 1977, for maximum lawful prices under § 271.402(c)(1);

(ii) November 1978, for maximum lawful prices under § 271.502(b)(2); and

(iii) the month in which the effective date of the rollover contract occurs, for maximum lawful prices under § 271.602(a)(1).

(Natural Gas Act, as amended, (15 U.S.C. 717 et seq.), Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Energy Supply and Environmental Coordination Act, (15 U.S.C. 791, et seq.), Federal Energy Administration Act, (15 U.S.C. 761 et seq.), Department of Energy Organization Act, Pub. L. 95-91, 42 U.S.C. 7107 et seq., (E.O. 12009, 42 FR 46267))

[43 FR 56551, Dec. 1, 1978; 43 FR 59482, Dec. 21, 1978; as amended at 44 FR 48664, Aug. 20, 1979; 45 FR 7782, Feb. 5, 1980; 45 FR 16173, Mar. 13, 1980; 45 FR 29570, May 5, 1980; and 45 FR 50557, July 30, 1980; 45 FR 73027, Nov. 4, 1980]

Subpart B--New Natural Gas and Certain Natural Gas Produced from the Outer Continental Shelf

AUTHORITY: (Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. 7107 et seq.; E.O. 12009, 42 FR 46267.

SOURCE: Order 42, 44 FR 48183, Aug. 17, 1979, unless otherwise noted.

§ 271.201 Applicability.

This subpart implements section 102 of the NGPA and applies to the first sale of:

(a) new natural gas; or

(b) natural gas produced from a new OCS reservoir on an old OCS lease.

§ 271.202 Maximum lawful price.

The maximum lawful price, per MMBtu, for natural gas to which this subpart applies shall be the price specified for Subpart B of Part 271 in Table I of § 271.101(a).

[44 FR 48664, Aug. 20, 1979]

§ 271.203 Definitions.

For purposes of this subpart:

(a) "New natural gas" means natural gas which a jurisdictional agency has determined, in accordance with Parts 274 and 275 and section 102(c) of the NGPA, to be new natural gas.

(b) "Natural gas from a new OCS reservoir on an old OCS lease" means natural gas which the jurisdictional agency determines, in accordance with Parts 274 and 275 and under section 102(d) (1), (2), (3), (4), and (5) of the NGPA, to be natural gas produced from a reservoir which is on an old OCS lease and which was not discovered before July 27, 1976.

(c) "OCS lease" means a lease of submerged acreage which is entered into with the Secretary of the Interior under the Outer Continental Shelf Lands Act, as amended, (43 U.S.C. 1331, et seq.).

(d) "New OCS lease" means an OCS lease entered into by the Secretary of the Interior on or after April 20, 1977.

(e) "Old OCS lease" means an OCS lease other than a new OCS lease.

§ 271.204 Special rules.

(a) Vertical measurement of 1,000 feet between completion locations. For the purpose of determining under section 102(c)(1)(B)(ii) of the NGPA the vertical distance between the deepest marker well completion location and the completion location for the new well for which the determination is sought, measurement shall be the true vertical depth measured from the highest perforation point of the deepest marker well completion location to the highest perforation point of the new well completion location. In the case of any well which is an open-hole completion, measurement shall be from the highest elevation point within the well bore of the reservoir being produced.

(b) Capable of producing in paying quantities. For purposes of section 102(d)(2)(B)(i) and (ii) of the NGPA, a reservoir is capable of producing in paying quantities if a well completed therein can reasonably be expected to produce natural gas in quantities sufficient to yield revenues in excess of operating costs. For the purposes of this paragraph, operating costs include those out-of-pocket cash expenses necessary to operate and maintain a well.

(c) Commercially producible. For purposes of section 102(d)(2)(B)(iii) of the NGPA, a reservoir is commercially producible if a well completed therein can reasonably be expected to produce natural gas in quantities sufficient to yield revenues in excess of operating costs. For the purposes of this paragraph, operating costs include those out-of-pocket cash expenses necessary to operate and maintain a well.

(d) Suitable facilities. For purposes of section 102(c)(1)(C)(iii)(II) of the NGPA (but subject to section 102(c)(1)(C)(iv) thereof), suitable facilities for the production and delivery of natural gas described in section 102(c)(1)(C)(iii)(I) of the NGPA were in existence on April 20, 1977, if on that date facilities for the production and delivery of natural gas to a pipeline were:

(1) installed; or

(2) substantially installed and additional facilities necessary for such production and delivery were readily available and could have been installed by April 20, 1977.

(e) Production in commercial quantities. For purposes of determining whether production of natural gas in commercial quantities has occurred under section 102(c)(1)(C) of the NGPA:

(1) A rebuttable presumption exists that production from a reservoir in commercial quantities has not occurred if natural gas has not been sold and delivered from such reservoir before April 20, 1977. Such presumption may be rebutted by evidence of retention of the natural gas by the operator, or owner of the production at severance, for beneficial economic use; and

(2) Quantities of natural gas sold in interstate commerce (within the meaning of the Natural Gas Act) before November 9, 1978, shall not be taken into account if such sales were made:

(i) under section 6 of the Emergency Natural Gas Act of 1977; or

(ii) under the emergency sale authority pursuant to Opinion No. 699-B, issued by the Commission under section 7(c) of the Natural Gas Act.

(f) Could have been produced in commercial quantities. For purposes of determining under section 102(c)(1)(C)(ii)(II) of the NGPA, whether natural gas from a reservoir could have been produced in commercial quantities through an old well which penetrated such reservoir before April 20, 1977.

(1) A rebuttable presumption exists that a reservoir could not have been produced in commercial quantities prior to April 20, 1977, through such old well if:

(i) No sales and deliveries of natural gas were made prior to April 20, 1977, through such well; and,

(ii) No sales and deliveries of natural gas from the subject reservoir were made through such well on or after April 20, 1977, and before November 9, 1978.

(2) If such rebuttable presumption is not met, then the first seller must clearly demon-

strate that the sale of the production from such reservoir through such old well at the market price reasonably available as of April 20, 1977, could not reasonably have generated revenues (net of royalty) equal to or greater than the sum of (i) 1.6 times the minimum incremental costs (properly allocable to such production) of installing cost-efficient facilities (not in existence as of April 20, 1977) reasonably required to market such production, plus (ii) the minimum incremental expenses (properly allocable to such production) reasonably required to operate such facilities. All costs, expenses, and revenues shall be determined as of April 20, 1977.

[Order 42, 44 FR 48183; Aug. 17, 1979, as amended by Order 42-A, 44 FR 69647, Dec. 4, 1979]

Subpart C—New, Onshore Production Wells

AUTHORITY: Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Department of Energy Organization Act, 42 U.S.C. 7107 et seq., Exec. Order No. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350.

SOURCE: Order 43, 44 FR 49655, Aug. 24, 1979, unless otherwise noted.

§ 271.301 Applicability.

This subpart implements section 103 of the NGPA and applies to the first sale of natural gas produced from a new, onshore production well.

§ 271.302 Maximum lawful price.

The maximum lawful price, per MMBtu, for natural gas to which this subpart applies shall be the price specified for Subpart C of Part 271 in Table I of § 271.101(a).

§ 271.303 Definition of new, onshore production well.

For purposes of this subpart, the term "new, onshore production well" means a well which a jurisdictional agency has determined, in accordance with Parts 274 and 275, to be a new, onshore production well (as defined in section 103(c) of the NGPA).

§ 271.304 Waivers of well-spacing requirements.

If a jurisdictional agency alters or grants a waiver of any applicable well-spacing requirements, the new well for which a determination is sought shall be deemed to satisfy any applicable Federal or State well-spacing requirements as required by section 103(c)(2) of the NGPA.

[44 FR 67111, Nov. 23, 1979]

§ 271.305 Special rule applicable to existing proration units.

(a) Applicability. (1) This section applies only to a jurisdictional agency determination with respect to a new well which is within a State law proration unit:

(i) Which was in existence at the time the surface drilling of such well began;

(ii) Which was applicable to the reservoir from which natural gas from such well is produced; and

(iii) Which applied to a well:

(A) Which produced natural gas in commercial quantities; or

(B) The surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

(2) For purposes of this paragraph, State law proration unit means a proration unit, drilling unit or similar unit expressly designated in accordance with State law or Federal law (other than the NGPA).

(b) Wells spudded on or after February 19, 1977.

(1) In order for natural gas from a well to which this section applies to qualify for the maximum lawful price under this subpart, the juisdictional agency must explicitly find that the well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit. This explicit finding must be based on appropriate geological and engineering data and such data must be included in the notice of determination submitted to the Commission.

(2) [Reserved]

(c) Notice of finding. If the jurisdictional agency makes a finding under paragraph (b)(1) of this section, it shall notify the Commission of such a determination in accordance with § 274.104.

(d) Rebuttable presumption for certain wells drilled on existing proration units. For the purposes of section 103(c)(3)(C) of the NGPA and paragraph (a)(1)(iii) of this section, if a well has been plugged and abandoned prior to January 1, 1970, and has not produced natural gas on or after that date, a rebuttable presumption is created that the well has not produced and is not capable of producing natural gas in commercial quantities.

[44 FR 67112, Nov. 23, 1979]

Subpart D--Natural Gas Committed or Dedicated to Interstate Commerce

AUTHORITY: Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 33650, 15 U.S.C. §§ 3301 to 3432; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.

SOURCE: Order 64, 45 FR 1871, Jan. 9, 1980, unless otherwise noted.

§ 271.401 Applicability.

This subpart implements sections 104 and 106(a) of the NGPA and applies to the first sale of natural gas committed or dedicated to interstate commerce on November 8, 1978, and for which a just and reasonable rate under the Natural Gas Act was in effect on November 8, 1978, for the sale of such gas.

§ 271.402 Maximum lawful prices.

(a) Ceiling prices. Unless a different rate is applicable under paragraph (c) of this section, the maximum lawful price for a category of natural gas to which this subpart applies shall be the price specified in Table II of § 271.101(a) for such category of gas.

(b) Definitions. For the purposes of this section:

(1) "Post-1974 gas" means natural gas to which this subpart applies which is produced from a well the surface drilling of which commenced on or after January 1, 1975.

(2) "1973-1974 biennium gas" means natural gas, to which this subpart applies, from a well the surface drilling of which commenced on or after January 1, 1973, and prior to January 1, 1975.

(3) "Interstate rollover gas" means:

(i) natural gas to which this subpart applies which is sold under a rollover contract as defined in section 2(12) of the NGPA; or

(ii) natural gas to which this subpart applies which is sold under a contract which would have been a rollover contract, but for the fact that the expiration of the previous contract occurred prior to November 9, 1978.

(4) "Replacement contract gas or recompletion gas" means natural gas to which this subpart applies which is:

(i) sold under a replacement contract which was executed on or after January 1, 1973, but prior to November 9, 1978, where the prior contract expired by its own terms prior to January 1, 1973; or

(ii) sold under a replacement contract executed prior to November 9, 1978, where the prior contract expired by its own terms after January 1, 1973; or

(iii) sold under a contract for the sale of natural gas from a well commenced prior to January 1, 1973, and not sold in interstate commerce prior to January 1, 1973, (excluding gas sold prior to such date under §§ 2.68, 2.70, 157.22 or 157.29 of this chapter); or

(iv) produced as a result of a completion operation into a different formerly nonproductive reservoir, commenced on or after January 1, 1973, and produced through a well commenced prior to January 1, 1973.

(5) "Certain Permian Basin gas" means natural gas (other than replacement contract gas or recompletion gas) to which this subpart applies and which is produced in the Permian Basin Area, as defined in FPC Opinion No. 662 (50 F.P.C. 390 at 400-401) and is sold pursuant to a contract executed on or after October 1, 1968.

(6) "Certain Rocky Mountain gas" means natural gas (other than replacement contract gas or recompletion gas) to which this subpart applies and which is produced in the Rocky Mountain Area, as defined in § 154.109(b) of this chapter and sold pursuant to a contract executed on or after October 1, 1968.

(7) "Certain Applachian Basin gas" means natural gas (other than replacement contract gas or recompletion gas) to which this subpart applies and which is produced by a large producer either (i) in the south sub-area under contracts dated October 7, 1969, or (ii) in the north sub-area, of the Applachian Basin Area, as defined in § 154.107 of this chapter.

(8) "Flowing gas" means natural gas to which this subpart applies (other than natural gas described in the preceding subparagraphs of this paragraph) produced from a well the surface drilling of which commenced prior to January 1, 1973.

(9) "Minimum rate gas" means natural gas to which this subpart applies produced from a well the surface drilling of which commenced prior to January 1, 1973, and which is sold pursuant to a contract providing for a fixed rate lower than that applicable to such gas under paragraph (c).

(10) A sale qualifies as a small producer sale under this subpart: (i) if it is a small producer sale (as defined in § 157.40(a)) covered by a blanket certificate under § 157.40(b) and (d), or (ii) if it is a sale by a large producer from small producer reserves, and such sale is entitled to the small producer rate under § 157.40(f)(2).

(11) A large producer sale is a first sale which does not qualify as a small producer sale under paragraph (b)(10) of this section.

(c) Applicable higher rates.

(1) If a just and reasonable rate in effect on April 20, 1977, under §§ 2.56a(g), 2.56b(h), 2.76 or 2.77 of this chapter was applicable on November 30, 1978, to a first sale of natural gas, then such rate (plus an inflation adjustment from April, 1977, determined in accordance

with § 271.102), if higher, shall apply in lieu of the rate determined under paragraph (a).

(2) Any just and reasonable rate for a sale of natural gas which was established by the Commission after April 20, 1977, and before November 9, 1978, shall be the maximum lawful price applicable to such sale if higher than the otherwise applicable rate prescribed under paragrpah (a) or (c)(1) of this section.

(3) In the case of any first sale under any rollover contract to which this subpart applies, the maximum lawful price for month in which the effective date of such rollover contract occurs shall be higher of: (i) The maximum lawful price applicable to the expiring contract on the date of the rollover occurs or (ii) the maximum lawful price specified in Table II of § 271.101(a) for interstate rollover gas.

(4) for purposes of §§ 271.402(b)(1) and (2), production from reservoirs penetrated for the first time through deeper drilling in an existing well is eligible for the same rate as if the deeper drilling constituted the commencement of surface drilling of such well. Deeper drilling means drilling after the first completion and production in a well bore have been accomplished, or drilling below an uncompleted nonproductive horizon where the initial well bore was plugged and abandoned.

(5) Any seller seeking to charge a rate in excess of the applicable maximum lawful price described in paragraph (a), or (c)(1), or (c)(2) of this section must first file a petition seeking special relief pursuant to § 1.7 (b) of this chapter fully justifying the relief sought. Such seller may not file a rate increase for, or charge or collect any rate in excess of the maximum lawful price otherwise applicable under this section unless the Commission has granted such petition for special relief.

(6) Notwithstanding § 270.101(b), the minimum rate for minimum rate gas (at 14.73 psia and 60° F) shall be the rate specified for minimum rate gas in Table II of § 271.101(a).

[Order 64, 45 FR 1871, Jan. 9, 1980, as amended at 44 FR 48664, Aug. 20, 1979; 45 FR 5685, Jan. 24, 1980; 45 FR 16173, Mar. 13, 1980]

§ 271.403 Special rule regarding carrying charge adjustment for advance payments.

The rate prescribed in § 271.402 for post-1974 gas to which Opinion No. 770-A applies shall be subject to a deduction of 83 cents per MMBtu as as a carrying charge adjustment if the seller has accepted advance payments on or after 1:00 p.m., EST, November 5, 1976, under an advance payments contract with an interstate pipeline company and such pipeline company has received rate base treatment of such advance payments made. The resulting adjusted rate shall be employed in the discharge of the obligations of any advance payments after 1:00 p.m., EST, November 5, 1976, for all deliveries until an amount of natural gas has been delivered at the adjusted rate such that the total carrying charge credits equal the amounts lawfully collected by the jurisdictional pipeline company as a result of including the advance payments in rate base.

Subpart E--Sales Under Existing Intrastate Contracts

AUTHORITY: Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Department of Energy Organization Act, 47 U.S.C. 7101-7352; E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978; 15 U.S.C. 3301-3432.

SOURCE: Order 68, 45 FR 5684, Jan. 24, 1980, unless otherwise noted.

§ 271.501 Applicability.

This subpart implements section 105 of the NGPA and applies to the first sale of natural gas under an existing intrastate contract or under a successor to an existing intrastate contract. This subpart is not applicable to sales made under an intrastate rollover contract as defined in § 270.102(b)(11) of this part.

§ 271.502 Maximum lawful prices.

(a) November 9, 1978, contract price at or below $2.060 per MMBtu. In the case of a first sale of natural gas to which this subpart applies (other than a first sale to which paragraph (b) applies), the maximum lawful price for natural gas delivered in any month shall be the lower of:

(1) the price for such month under the terms of the existing intrastate contract to which such natural gas was subject on November 9, 1978, as such contract was in effect on November 9, 1978; or

(2) The maximum lawful price per MMBtu for such month specified for new natural gas (Subpart B of Part 271) in Table I of § 271.101(a).

(b) November 9, 1978, contract price greater than $2.060 per MMBtu. In the case of a first sale of natural gas to which this subpart applies, if the contract price applicable on November 9, 1978, was greater than $2.060 per MMBtu, the maximum lawful price for natural gas delivered in any month shall be the higher of:

(1) The maximum lawful price per MMBtu for such month specified for new natural gas (Subpart B of Part 271) in Table I of § 271.101(a); or

(2) the contract price per MMBtu on November 9, 1978, adjusted for inflation in accordance with § 271.102 of this part.

§ 271.503 Filing requirements.

Any person who collects a price under this subpart shall file reports required by § 276.101 of this chapter.

§ 271.504 Determination of contract price.

For purposes of this subpart:

(a) Contract price. "Contract price," when used with respect to any specific date and contract, means:

(1) The total price paid per MMBtu for delivery of natural gas occurring on that date (including any amounts which were required to be paid as reimbursement from the purchaser for State severance taxes paid by the seller).

(2) If no deliveries of natural gas occurred under such contract on that date, the total price per MMBtu that would have been paid for delivery of natural gas on that date (including any amount which would have been required to be paid as reimbursement from the purchaser for State severance taxes which would have been paid by the seller).

(b) Price under the terms of the existing contract. "Price under the terms of the existing contract" when used with respect to any specific date and contract means the total price under the terms of the existing contract, as such contract was in effect on November 9, 1978 (including any amounts which are required to be paid as reimbursement from the purchaser for State severance taxes paid by the seller).

(c) Take-or-pay clause. If the contract contains a take-or-pay clause and payments were made under such clause for deliveries on November 9, 1978, the contract price on November 9, 1978, shall be determined as if volumes obligated to be taken were taken.

[45 FR 76670, Nov. 20, 1980]

§ 271.505 Contract modifications.

(a) General rule. Except as provided in paragraph (b) of this section, for purposes of this subpart, no successor to an existing intrastate contract or modification executed after November 9, 1978, of an existing intrastate contract may alter the terms of the existing intrastate contract in a manner which has the effect of requiring the purchaser to bear any production-related costs (as defined in § 271.102(b)(17)) which were allocated to the seller under the existing intrastate contract.

(b) Exception. Nothing in paragraph (a) of this section shall preclude a purchaser who was not a party to the existing intrastate contract on November 9, 1978, from agreeing, by modifications of the existing intrastate contract, or otherwise, to bear responsibility and pay for any increase (or portion thereof) in any production-related costs which were allocated to the seller under the existing intrastate contract and incurrence of which is necessary in order for such purchaser to take delivery of the natural gas subject to the existing intrastate contract.

(c) Costs not allocated to the seller. Nothing in paragraph (a) of this section shall preclude the seller from applying under the provisions of § 271.1104(b)(1) for the recovery of production-related costs which were not allocated to the seller under the existing intrastate contract if recovery of such costs is authorized by contract.

[45 FR 76681, Nov. 20, 1980]

Subpart F--Intrastate Rollover Contracts

AUTHORITY: Natural Gas Act, as amended, 15 U.S.C. 717, et seq.; Department of Energy Organization Act, 47 U.S.C. 7101-7352; E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978; 15 U.S.C. 3301-3432.

SOURCE: Order 68, 45 FR 5684, Jan. 24, 1980, unless otherwise noted.

§ 271.601 Applicability.

This subpart implements section 106(b) of the NGPA and applies to the first sale of natural gas under an intrastate rollover contract.

§ 271.602 Maximum lawful price.

(a) General rule. The maximum lawful price for a first sale of natural gas under an intrastate rollover contract to which section 106(b)(1) of the NGPA applies shall be the higher of:

(1)(i) The maximum lawful price, per MMBtu, paid under the expired contract, in the case of the month in which the effective date of such rollover contract occurs; and

(ii) In the case of any month thereafter, the maximum lawful price, per MMBtu, prescribed under this paragraph for the preceding month adjusted for inflation in accordance with § 271.102; or

(2) The alternative maximum lawful price specified in Table I of § 271.101(a) for certain intrastate rollover gas.

(b) Certain State or Indian production or royalty shares. The maximum lawful price, per MMBtu, for natural gas to which section 106(b)(2) of the NGPA (relating to certain State or Indian natural gas production or royalty interests) applies shall be the price specified for new natural gas (Subpart B of Part 271) in Table I of § 271.101(a).

(c) Qualified production enhancement gas. For purposes of paragraph (a)(1)(i) of this section, the maximum lawful price, per MMBtu, paid under the expired contract is deemed to include

any amount paid by reason of a maximum lawful price allowed under § 271.704 (relating to qualified production enhancement gas.)

[45 FR 77429, Nov. 24, 1980]

§ 271.603 Filing requirements.

Any person who collects a price under this subpart shall file reports required by § 276.101 of this chapter.

§ 271.604 Special rules.

(a) Maximum lawful price paid under the expired contract. For purposes of this subpart, the maximum lawful price paid under the expired contract shall not include any costs authorized and collected under the provisions of Subpart K of this Part.

(b) Production-related borne by the purchaser.

(1) General rule. Except as provided in clause (2) of this paragraph, for purposes of this subpart, no intrastate rollover contract may require the purchaser to bear any production-related costs (as defined in § 270.102(b)(17) which were allocated to the seller under the expired contract.

(2) Exception. Nothing in clause (1) of this paragraph shall preclude a purchaser who was not a party to the expired contract on November 9, 1978, from agreeing in the intrastate rollover contract to bear responsibility and pay for any increase (or portion thereof) in any production-related cost which was allocated to the seller under the expired contract, incurrence of which is necessary in order for such purchaser to take delivery of the natural gas subject to the intrastate rollover contract.

(c) Costs not allocated to the seller. Nothing in paragraph (b) of this section shall preclude the seller from applying under the provisions of § 271.1104(b)(1) for the recovery of production-related costs which were not allocated to the seller under the expired contract.

[45 FR 76681, Nov. 20, 1980]

Subpart G—High-Cost Natural Gas

AUTHORITY: Dept. of Energy Organization Act (42 U.S.C. 7101 et seq.); E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978 (15 U.S.C. 3301-3432)

SOURCE: 45 FR 13424, Feb. 28, 1980, unless otherwise noted.

§ 271.701 Applicability.

This subpart implements section 107(b) and (c) of the NGPA and applies to the first sale of natural gas which is:

(a) Tight formation gas for which there is a negotiated contract price.

(b) Qualified production enhancement gas.

[45 FR 28098, Apr. 28, 1980; 45 FR 56044, Aug. 22, 1980; 45 FR 71564, Oct. 29, 1980; 45 FR 77429, Nov. 24, 1980]

§ 271.702 General rules.

(a) Definitions. For purposes of this subpart:

(1) "Negotiated contract price" means any price established by a contract provision that specifically references the incentive pricing authority of the Commission under section 107 of the NGPA by a contract provision that prescribes a specific fixed rate, or by the operation of a fixed escalator clause.

(2) A "fixed escalator clause" is a provision in a contract for the first sale of natural gas which changes the price for the gas by a specified amount on a specified date.

(3) For the definition of "crude oil," see § 270.102(b)(5).

(b) Cross reference. For special rules applicable to high-cost natural gas retroactive collections, see § 273.204.

[45 FR 28098, Apr. 28, 1980; 45 FR 56044, Aug. 22, 1980; 45 FR 71564, Oct. 29, 1980]

§ 271.703 Tight formations.

(a) Maximum lawful price for tight formation gas. The maximum lawful price, per MMBtu, for the first sale of tight formation gas for which there is a negotiated contract price shall be the lesser of:

(1) The negotiated contract price; or

(2) 200 percent of the maximum lawful price specified for Subpart C of Part 271 in Table I of § 271.101(a).

(b) Definitions. (1) "Tight formation gas" means natural gas that a jurisdictional agency has determined in accordance with Parts 274 and 275 to be new tight formation gas or recompletion tight formation gas.

(2) "New tight formation gas" is natural gas:

(i) Which is new natural gas, (as defined in section 102(c)), certain OCS gas qualifying for the new natural gas ceiling price (as defined in section 102(d)), or gas produced through a new onshore production well (as defined in section 103(c)); and

(ii) Which is produced from a designated tight formation through a well the surface drilling of which began on or after July 16, 1979.

(3) "Recompletion tight formation gas" is natural gas which is produced from a designated tight formation through a well, the surface drilling of which was begun before July 16,

1979, if such well was not completed for production from such designated formation before July 16, 1979.

(4) "Formation" means any geological formation, or portion thereof described by geological as well as geographical parameters.

(5) A "designated tight formation" is a natural gas formation which is designated a tight formation by the Commission pursuant to paragraph (c) of this section.

(6) "Infill drilling" means any drilling in a substantially developed formation (or a portion thereof) subject to requirements respecting well-spacing or proration units which were amended by the jurisdictional agency after the formation (or portion thereof) was substantially developed and which were adopted for the purpose of more effective and efficient drainage of the reservoirs in such formation. Such amendment may provide for the establishment of smaller drilling or production units or may permit the drilling of additional wells on the original units.

(c) Designation of tight formations--

(1) General. Upon the written recommendation by a jurisdictional agency, submitted in accordance with the requirements of this section, the Commission may approve a recommendation that a natural gas formation be designated as a tight formation.

(2) Guidelines. (i) The Commission will approve the designation of any formation recommended by a jurisdictional agency if the formation meets each of the following guidelines:

(A) The estimated average in situ gas permeability, throughout the pay section, is expected to be 0.1 millidarcy or less.

(B) The stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation, is not expected to exceed the production rate determined in accordance with the following table:

If the average depth to the top of the formation (in feet)		The maximum allowable production rate
Exceeds	But does not exceed	(in the thousand cubic feet per day) may not exceed
0..........	1,000	44
1,000......	1,500	51
1,500......	2,000	59
2,000......	2,500	68
2,500......	3,000	79
3,000......	3,500	91
3,500......	4,000	105
4,000......	4,500	122
4,500......	5,000	141
5,000......	5,500	163
5,500......	6,000	188
6,000......	6,500	217
6,500......	7,000	251
7,000......	7,500	290
7,500......	8,000	336
8,000......	8,500	388
8,500......	9,000	449
9,000......	9,500	519
9,500......	10,000	600
10,000......	10,500	693
10,500......	11,000	802
11,000......	11,500	927
11,500......	12,000	1,071
12,000......	12,500	1,238
12,500......	13,000	1,432
13,000......	13,500	1,655
13,500......	14,000	1,913
14,000......	14,500	2,212
14,500......	15,000	2,557

TABLE--(Continued)

(C) No well drilled into the recommended tight formation is expected to produce, without stimulation, more than five barrels of crude oil per day.

(D) If the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation.

(ii) The Commission will consider and may approve or disapprove a recommendation by a jurisdictional agency to designate as a tight formation any formation which meets the guidelines contained in paragraph (c)(2)(i)(B) and (C) of this section, but does not meet the guideline contained in paragraph (c)(2)(i)(A) of this section, if the jurisdictional agency makes an adequate showing that the formation exhibits low permeability characteristics and the price established in paragraph (a) of this section is necessary to provide reasonable incentives for production of the natural gas from the recommended formation due to the extraordinary costs associated with such production.

(3) Content of recommendations. A recommendation that a formation should qualify as a designated tight formation shall contain the following information:

(i) Geological and geographical descriptions of the formation which is recommended for classification as a tight formation;

(ii) Geological and engineering data to support the recommendation and the source of that data;

(iii) A map which clearly locates wells which are currently producing from the recommended

tight formation or a list locating all wells which are currently producing natural gas from the recommended tight formation;

(iv) A report of the extent to which existing State and Federal regulations will assure development of the recommended tight formation will not adversely affect any fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used as a domestic or agricultural water supply;

(v) If the formation is recommended under paragraph (c)(2)(ii) of this section, the types and extent of enhanced production techniques which are expected to be necessary and the estimated expenditures necessary for employing those techniques; and the degree of increase in production to be expected from use of such techniques and engineering and geological data to support that estimate;

(vi) Any other information which the jurisdictional agency deems relevant; and

(vii) Any other information requested by the Commission.

(4) Commission review of recommendations. Upon receipt of a recommendation submitted in accordance with this section, the Commission shall publish in the Federal Register a notice of proposed rulemaking containing such recommendation. After review of any comments, the Commission will prescribe a rule approving or disapproving the recommendation.

(d) Designated tight formations. The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

(1) The Cotton Valley Group in Texas. The Cotton Valley Group consists of the Cotton Valley Sandstone, the Bossier Shale and the Cotton Valley Lime Formations, RM79-76 (Texas-1).

(i) Delineation of formations. The northern boundary of the Cotton Valley Group is the Texas-Oklahoma border extending through Fannin, Lamar, and Red River Counties; the eastern boundary is formed by the Texas-Arkansas and Texas-Louisiana borders; the southern boundary is along the Angelina-Caldwell flexture running through Sabine, San Augustine, Angelina and Trinity Counties; the western boundary is set by the Mexia-Talco fault zone through Limestone, Navarro, and Kaufman Counties.

(ii) Depth. Cotton Valley Sandstone is encountered at an average depth of approximately 7,000' to the north, 8,000' to the east, between 10,000' and 11,000' to the south, and 5,000' to the west; Bossier Shale is encountered at 7,700' to the north, 10,720' to the east, 12,600' to the south, and 5,340' to the west; Cotton Valley Lime is encountered at 8,000' to the north, 11,400' to the east, 13,200' to the south, and 5,500' to the west.

(2) The Mancos "B" Formation in Colorado, RM79-76 (Colorado-2).

(i) Delineation of formation. The Mancos "B" Formation is located approximately midway between Grand Junction and Rangely, Colorado, and straddles the Rio Blanco-Garfield county line from the Utah-Colorado state line east to the Douglas Pass and Baxter Pass Unit Area, underlying approximately 195,200 contiguous acres of land in Rio Blanco and Garfield Counties, Colorado.

(ii) Depth. The average depth to the top of the Mancos "B" Formation is approximately 3,475 feet.

(3) The Frontier Formation in Wyoming, RM79-76 (Wyoming-1).

(i) Delineation of Formation. The Frontier Formation is located in the Moxa Arch area in portions of Sweetwater, Uinta, and Lincoln Counties, Wyoming.

(ii) Depth. The top of the Frontier Formation is marked by the Hilliard Shale above, and the bottom of the formation is marked by the Mowry Shale, below. The average depth of the top of the Frontier Formation ranges from approximately 11,100 feet to 11,140 feet.

(4) The Mesaverde Formation in Wyoming, RM 79-76 (Wyoming-2).

(i) Delineation of formation. The Mesaverde Formation is located in the Wamsutter Area in portions of Sweetwater, and Carbon Counties, Wyoming.

(ii) Depth. The top of the Frontier Formation is marked by the Lewis Shale above and the bottom of the formation is marked by the Steele Shale, below. The average depth to the top of the formation is approximately 10,125 feet.

(5) The Austin-Mississippian Formation in New Mexico, RM79-76 (New Mexico-1).

(i) Delineation of formation. The Austin-Mississippian Formation is located entirely within Lea County, New Mexico. The area consists of 138,240 contiguous acres of land located approximately 6 to 12 miles north of Lovington, New Mexico.

(ii) Depth. The average depth to the top of the Austin-Mississippian Formation is approximately 13,250 feet.

(6) The Mancos "B" Formation in Colorado, RM 79-76 (Colorado-6).

(i) Delineation of formation. The Mancos "B" Formation is located in northwestern Colorado in the North Douglas Creek area in Rio Blanco County, Colorado, approximately 10 miles south of the town of Rangely, Colorado, on the Douglas Creek Arch which separates the Uinta and Piceance Creek Geologic Basins.

(ii) Depth. The average depth to the top of the Mancos "B" Formation is approximately 2,500 feet.

(7) The Fort Union Formation in Colorado, RM

79-76 (Colorado-4).

(i) Delineation of formation. The Fort Union Formation is located in the Rio Blanco and Dry Gulch Units of Rio Blanco County, Colorado, approximately 40 miles southwest of Meeker, Colorado, and 30 miles northwest of Rifle, Colorado. The area is bounded on the north and south by synclinal and anticlinal trends, and on the northeast by an anticlinal closure known as the Piceance Creek Dome.

(ii) Depth. The average depth to the top of the Fort Union Formation is approximately 4,700 feet.

(8) The Mesaverde Formation in Colorado, RM 79-76 (Colorado-4).

(i) Delineation of formation. The Mesaverde Formation is located in the Rio Blanco and Dry Gulch Units of Rio Blanco County, Colorado, approximately 40 miles southwest of Meeker, Colorado, and 30 miles northwest of Rifle, Colorado. The area is bounded on the north and south by synclinal and anticlinal trends, and on the northeast by an anticlinal closure known as the Piceance Creek Dome.

(ii) Depth. The average depth to the top of the Mesaverde Formation is approximately 7,200 feet.

(9) The Mancos Formation to the base of the Mancos "B" Zone in Colorado, RM79-76 (Colorado-4).

(i) Delineation of formation. The Mancos Formation to the base of the Mancos "B" Zone is located in the Rio Blanco and Dry Gulch Units in Rio Blanco County, Colorado, approximately 40 miles southwest of Meeker, Colorado, and 30 miles northwest of Rifle, Colorado. The area is bounded on the north and south by synclinal and anticlinal trends, and on the northeast by an anticlinal closure known as the Piceance Creek Dome.

(ii) Depth. The average depth of the top of Mancos Formation is approximately 10,500 feet.

(10) The Canyon Sandstone Formation in Texas, RM 79-76 (Texas-2).

(i) Delineation of formation. The Canyon Sandstone Formation is found in portions of Crockett, Edwards, Schleicher, Sutton, Terrell and Val Verde Counties, Texas.

(ii) Depth. In the east, the top of the Upper Canyon (Sonora) of the Canyon Sandstone Formation is encountered at a depth of approximately 4,775 feet and the base of the Lower Canyon extends to 8,953 feet, for a total thickness of 4,178 feet. In the west, the top of the Upper Canyon (Ozona), the only section of the Canyon Sandstone Formation to occur in the west, is encountered at an approximate depth of 2,675 feet in the south and 6,100 feet in the north. The base of the Upper Canyon (Ozona) appears at an approximate depth of 3,915 feet in the south, and 7,278 feet in the north, and its thickness ranges from approximately 1,240 feet in the north to 1,178 feet in the south.

[45 FR 28098, Apr. 28, 1980; 45 FR 56044, Aug. 22, 1980; 45 FR 71565, Oct. 29, 1980; 45 FR 71780, Oct. 30, 1980; 45 FR 76672, 74, 76, Nov. 20, 1980; 45 FR 84035-36-37, Dec. 22, 1980]

§ 271.704 Qualified production enhancement gas.

(a) Maximum lawful price for qualified production enhancement gas.

(1) The maximum lawful price, per MMBtu, for the first sale of qualified production enhancement gas shall be the lesser of:

(i) The renegotiated price stated in the application; or

(ii) The section 109 price.

(2) Requirement of completed production enhancement work. If the production enhancement work has not been completed on or before the date the application is filed, the maximum lawful price provided in paragraph (a)(1) of this section shall not apply until the production enhancement work is completed and the seller has given written notice to the purchaser stating that the production enhancement work upon which the application for determination of eligibility is based, has been completed. The applicant must retain a copy of this notice in his records for a period of three years after the month in which the first sales priced under this section occurred.

(3) Elimination of price controls. For purposes of determining the price paid, under section 121(a)(3) of the NGPA, any amount paid solely by reason of a maximum lawful price allowed by this section shall be disregarded.

(b) Definitions. For purposes of this subpart:

(1) "Qualified production enhancement gas" means natural gas that a jurisdictional agency has determined in accordance with Part 274 and 275 meets the qualification requirements in paragraph (c) of this section.

(2) "Production enhancement work" means an operation or installations of equipment described in paragraph (d) of this section.

(3) "Renegotiated price" means a price (not in excess of the section 109 price) agreed to after November 9, 1978, in connection with the production enhancement work which is the subject of an application under this section.

(4) "Section 109 price" means the maximum lawful price specified for Subpart I of Part 271 in Table I of § 271.101(a).

(c) Qualified production enhancement gas. For purposes of this section:

(1) Qualified production enhancement gas is natural gas:

(i) Which is produced:

(A) From a well on which production enhancement work (other than production enhancement work described in paragraph (d)(3) of this section) was commenced on or after May 29,

1980; or

(B) From a zone that is perforated in accordance with paragraph (d)(3) of this section on or after May 29, 1980;

(ii) For which a maximum lawful price prescribed by Subpart E of Part 271 applies (but for this section);

(iii) For which a renegotiated price is applicable;

(iv) For the production of which there is a reasonable basis, grounded in part on the amount of the investment, to conclude that:

(A) The price prescribed in paragraph (a) of this section is necessary as a reasonable incentive; and

(B) But for the availability of the price prescribed in paragraph (a) of this section, the production enhancement work would not have been performed or will not be performed; and

(v) The production of which (as calculated by the seller for a five year period beginning from the month of application ("test period"), based on estimates filed pursuant to § 274.205 (f)(4)) will result in a projected increase in revenue which, when divided by the projected increase in units of production, does not exceed 200 percent of the maximum lawful price specified for Subpart C of Part 271 in Table I of § 271.101(a) for the month that the application is filed.

(2) "Projected increase in revenue" means:

(i) The product of (A) the estimated units of gas production (MMBtu's) which would be produced from the well during the test period if production enhancement work has been completed on the day that the application is filed, times (B) the section 109 price (unless paragraph (c)(4) of this section otherwise permits) for the month that the application is filed, less

(ii) The product of (A) the estimated units of gas production (MMBtu's) which would be produced from the well during the test period if the production enhancement work is not performed, or had not been performed, times (B) the maximum lawful price otherwise applicable to natural gas from the well as of the date the application is filed.

(3) "Projected increase in units of production" means:

(i) The estimated units of gas production (MMBtu's) which would be produced from the well during the test period if the production enhancement work had been completed on the day that the application is filed, less

(ii) The estimated units of gas production (MMBtu's) which would be produced from the well during the test period if the production enhancement work is not performed, or had not been performed.

(4) For purposes of paragraph (c)(2)(i)(B) of this section, if the renegotiated price is a fixed price or a percentage of the section 109 price, such renegotiated price (as of the date of application) may be substituted for the section 109 price in making the determination required in paragraph (c)(2) of this section.

(d) Production enhancement work defined. For the purposes of this section, "production enhancement work" means any work that is performed for one or more of the following purposes:

(1) Re-entry into a well which has been plugged and abandoned.

(2) Re-entry into a well for the purpose of deeper drilling, or sidetracking, to a different completion location.

(3) Recompletion by reperforation of a zone from which natural gas has been produced or by perforation of a different zone.

(4) Repair or replacement of faulty or damaged casing, tubing or related downhole equipment.

(5) Fracturing, acidizing or the installing of compression equipment.

(6) Installing equipment necessary for removal of excessive water, brine or condensate from the wellbore in order to establish, continue or increase production of gas from the well.

(7) Workover operations to reduce excessive water or brine production in order to establish, continue or increase production of gas from the well.

(8) Operations to dispose of water or brine produced from the well, the presence of which prevents or severely limits gas production from the well.

(9) Workover operations to reduce excessive sand production or operations to remove excessive sand from the wellbore in order to continue production of gas from the well.

(10) Injection of nitrogen gas or other inert gas necessary to establish, continue or increase production of gas from the reservoir.

(e) Cross reference. For the rule establishing the maximum lawful price for qualified production enhancement gas which becomes subject to an intrastate rollover contract, see § 271.602(c).

[45 FR 28098, Apr. 28, 1980; 45 FR 77429, Nov. 24, 1980]

Subpart H—Stripper Well Natural Gas

AUTHORITY: Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. § 7107, *et seq.*, E.O. 12009, 42 FR 46267.

SOURCE: Order 44, 44 FR 49662, Aug. 24, 1979, unless otherwise noted.

§ 271.801 Applicability.

This subpart implements section 108 of the NGPA and applies to any first sale of natural

gas which a jurisdictional agency determines is stripper well natural gas.

§ 271.802 Maximum lawful price.

The maximum lawful price, per MMBtu, for natural gas to which this subpart applies shall be the price specified for Subpart H of Part 271 in Table I of § 271.101(a).

§ 271.803 Definitions.

For purposes of this subpart:

(a) Recognized enhanced recovery techniques. "Recognized enhanced recovery techniques" means processes or equipment, or both, which when performed or installed by the producer, increase the rate of production of gas from a well. Processes qualifying as recognized enhanced recovery techniques include mechanical as well as as chemical stimulation of the reservoir formation. Equipment may include items installed in the well bore or on the surface.

Normal well maintenance, repair, or replacement of equipment or facilities does not qualify as enhanced recovery techniques. Normal completion operations (as defined by the jurisdictional agency or, if the agency has not defined the term, by state custom or practice) which are performed within two years of the initial completion do not qualify as recognized enhanced recovery techniques. Any drilling activity which results in production from another reservoir does not qualify as a recognized enhanced recovery technique.

(b) Nonassociated Natural Gas. "Nonassociated natural gas" means natural gas produced from a well which a jurisdictional agency determines produced an average number of barrels of crude oil per production day during the production period upon which the determination is based, which does not exceed the number of barrels determined in accordance with the following table:

If the average production of natural gas per production day during such production period was:	Then average crude oil production per day may not exceed:
50 Mcf. or more but not more than 60 Mcf.	1 bbl.
30 Mcf. or more but not more than 50 Mcf.	2 bbl.
Less than 30 Mcf.	3 bbl.

(c) 90-Day Production Period. (1) "90-day production period" means any period of 90 consecutive calendar days excluding any day during which natural gas is not produced for reasons other than voluntary action of any person with the right to control production of natural gas from such well.

(2) Where records for a 90-consecutive-calendar-day period indicate that the well produced 60 Mcf or less per production day during that period, a rebuttable presumption is created that the well produced 60 Mcf or less per production day during the 90-day production period defined in subparagraph (1) of this paragraph.

(d) Production Day. "Production day" means:

(1) Any day during which natural gas is produced; and

(2) Any day during which natural gas is not produced if production during such day is prohibited by a requirement of State law or a conservation practice recognized or approved by the State agency having regulatory jurisdiction over the production of natural gas.

(e) Produced. Natural gas is produced, within the meaning of section 108(b)(3)(A) and (B) of the NGPA:

(1) On any day during which there is measurable production of natural gas from a well, and

(2) On any day on which a well is open to the line but is unable to produce measurable quantities of gas.

[Order 44, 44 FR 49662, Aug. 24, 1979, as amended at 44 FR 66786, Nov. 21, 1979]

§ 271.804 Special rules.

(a) Rate of production. For purposes of determining the rate of production from a well for which a stripper well determination is sought:

(1) The total volume of natural gas produced from the well shall constitute its daily production regardless of whether the well is completed in more than one interval or the production is separately metered from separate intervals;

(2) Production may be measured either before or after the extraction of natural gas liquids.

(b) Averaging of production. If a determination of stripper well status is sought with respect to wells which are not individually metered, rates of production of natural gas and oil may, in the absence of other reliable evidence, be averaged equally among the nonmetered wells.

(c) Applications for determinations. Applications under this subpart shall be based on a 90-day production period which falls entirely within the 180 days prior to the date on which the application is filed.

(d) Seasonally affected wells. (1) If together with a petition for qualification as a stripper well, the applicant submits to the

jurisdictional agency production reports for a period of at least 24 months ending concurrently with a 90-day production period which is the basis for the application under paragraph (c) of this section and if such reports demonstrate that the well is subject to seasonal fluctuations which temporarily increase average production above 60 Mcf per production day, the jurisdictional agency may, upon request, designate the well as "seasonally affected." Such designation shall be granted by the jurisdictional agency only if it finds that the seasonal fluctuations have not increased and cannot reasonably be expected to increase production levels above an average of 60 Mcf per production day for any 12-month period.

(2) If at any time subsequent to a final determination of stripper well status, the operator acquires production reports for a period of 24 consecutive months which demonstrate that the well is "seasonally affected", a petition may be filed with the jurisdictional agency for designation as a seasonally affected well. The jurisdictional agency shall make the designation according to the standards described in paragraph (d)(1) of this section.

(3) If a well is designated as seasonally affected, the operator of such well and the purchaser of production from such well are exempt from the filing requirements of § 271.805 unless the average rate of production exceeds 60 Mcf per production day for a 12-month period.

§ 271.805 Continuing qualification.

(a) Notice of disqualification. (1) Unless exempt under § 271.804(d)(3), the operator and any purchaser of natural gas shall give written notice if:

(i) A well for which an application has been filed under this subpart or a determination has been made under this subpart produces natural gas at a rate exceeding an average of 60 Mcf per production day for any 90-day production period; or

(ii) A well which has been designated a seasonally affected well produces natural gas at an average rate in excess of 60 Mcf per production day for any 12-month period.

(2) Notice required under paragraph (a)(1) of this section shall be given within 90 days after the last day of the 90-day or the 12-month production period in which the increased production of natural gas occurred.

(3) Such notice shall be served on the jurisdictional agency and the Commission, and on the operator and any purchaser, as appropriate. Except as provided in paragraph (b) of this section, such notice shall terminate the right of any seller to continue the collection of the maximum lawful price set forth in § 271.802 for natural gas produced from the well identified in the notice.

(b) Petition under § 271.806. The operator may file with the jurisdictional agency (1) a motion contesting a notice filed by a purchaser under paragraph (a); or (2) a petition for a determination under § 271.806 that the increased production of natural gas is the result of the application of an enhanced recovery technique or, if the well has not been designated as seasonally affected, the result of seasonal fluctuations. Such petition or motion may be filed at any time after notice is given under paragraph (a). A copy of the petition or motion and of the notice required under paragraph (a)(1) of this section shall be provided to the Commission and to the purchaser.

(c) Effect of notice. If notice is served pursuant to paragraph (a) of this section, the well to which such notice applies shall immediately be disqualified as a stripper well and the right of any seller to collect the maximum lawful price set forth in § 271.802 shall terminate subject to in paragraph (d) as of the last day of the 90-day or the 12-month production period described in the notice unless, within 30 days of service the operator files a petition or motion with the jurisdictional agency as provided in paragraph (b) of this section.

(d) Collection subject to refund. An operator who files a petition or motion under paragraph (b) of this section may collect, subject to refund, the maximum lawful price set forth in § 271.802:

(1) From the last day of the 90-day or the 12-month production period to which the notice applies, if such petition or motion is filed within 30 days of the date notice is served under paragraph (a) of this section, or

(2) from the date such petition or motion is filed in all other cases.

(e) Filing requirements for increased production based on enhanced recovery techniques. If subsequent to the filing of a petition it is determined that the increase in production of natural gas is the result of recognized enhanced recovery techniques, neither the operator nor the purchaser shall be obligated to report average production levels above 60 Mcf per day during any 90-day production period unless there is an increase in production resulting from causes other than use of recognized enhanced recovery techniques determined to have been used.

[45 FR 80275, Dec. 4, 1980]

§ 271.806 Jurisdictional agency determinations and Commission review.

(a) Petitions under §§ 271.804(d) and 271.803(a). The jurisdictional agency in receipt of a petition to designate a well as a seasonally affected well pursuant to § 271.804(d) or a petition to determine that production in excess of an average of 60 Mcf per production

day was due to use of recognized enhanced recovery techniques defined in § 271.803(a), shall treat the petition as if it were an application for an initial determination and shall comply with the applicable provisions of Subpart A of Part 274.

(b) Review of determinations. Upon receipt of notice of a determination made under paragraph (a) of this section, the Commission will review such determination pursuant to the applicable provisions of Subpart B of Part 275.

(c) Declaratory order or staff interpretation. A jurisdictional agency, when making a determination under § 271.806(a) (relating to production in excess of 60 Mcf per production day resulting from the application of recognized enhanced recovery techniques), may seek a declaratory order or staff interpretation from the Commission that a process (or type of process) or the installation of equipment (or type of equipment) qualifies as a recognized enhanced recovery technique as defined in § 271.. 803(a). The petition for declaratory order shall be filed in accordance with the requirements of § 1.7(c) of the Commission's Rules of Practice and Procedure (18 CFR 1.7(c)).

§ 271.807 Maximum efficient rate of flow.

(a) Determination under recognized conservation practice. If a maximum efficient rate of flow for a well, determined in accordance with recognized conservation practices designed to maximize the ultimate recovery of natural gas, has been established by a jurisdictional agency, production of natural gas at that rate shall be deemed to be production at the maximum efficient rate of flow.

(b) Alternative methods for determination. If a maximum efficient rate of flow has not been determined in accordance with paragraph (a) by a jurisdictional agency, for a well which has produced nonassociated gas at an average rate of 60 Mcf per production day or less for a 90-day production period, the jurisdictional agency shall establish maximum efficient rate of flow in accordance with one of the following methods:

(1) Prior production data available. If production data are available for the 12-month period ending concurrently with such 90-day production period, the applicant shall submit such data.

(i) If such 12-months' production data established that the well produced natural gas at a rate which did not exceed an average of 60 Mcf per production day for such 12-month period, there is a rebuttable presumption that the well produced at its maximum efficient rate of flow.

(ii) If such 12-months' production data established that the well produced natural gas at a rate which did not exceed an average of 70 Mcf per production day for such 12-month period, the jurisdictional agency shall make a deferred determination in accordance with paragraph (c).

(2) Prior production data not available. If production data are not available for the 12-month period ending concurrently with such 90-day production period, the jurisdictional agency shall make a deferred determination in accordance with paragraph (c).

(3) Other evidence. The jurisdictional agency may base the determination upon other substantial evidence, such as flow tests, which measure the capability of the well to produce natural gas under normal operating conditions.

(c) Deferred determination procedure. If a determination is deferred under paragraph (b) (1) (ii) or (b)(2), the jurisdictional agency shall designate a 12-month period during which the applicant may secure the data establishing that the well produced natural gas at an average rate not in excess of 60 Mcf per production day. The applicant may submit such data not later than 90 days after the close of such 12-month period, and if such data show that the well's production did not exceed 60 Mcf per production day, the jurisdictional agency shall make an affirmative determination.

(d) Negative determinations. The jurisdictional agency shall make a negative determination as to eligibility if:

(1) The production data submitted by the applicant indicate that for the 12 months ending concurrently with the 90-day production period the well produced natural gas at a rate which exceeded an average of 70 Mcf per production day, unless the jurisdictional agency determines that the well produced at its maximum efficient rate of flow pursuant to paragraph (a)(1) or paragraph (b)(3).

(2) The production data submitted by the applicant indicate that for the deferred 12-month period established by the jurisdictional agency, the well produced natural gas at a rate which exceeded an average of 60 Mcf per production day, or

(3) The applicant fails to submit available production data pursuant to paragraph (b)(1) or fails to submit production data pursuant to paragraph (c).

(e) Interim collection. When the jurisdictional agency defers making a determination on an application pursuant to paragraph (b)(1)(ii) or (b)(2), the applicant shall be permitted to make interim collections of the maximum lawful price provided in § 271.802 pursuant to the requirements of § 273.202. If the filing requirements of § 273.202(d) have previously been complied with, the applicant shall not be required to make such filings again.

Subpart I--Other Categories of Natural Gas

AUTHORITY: Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Department of Energy Organization Act, 42 U.S.C. 7107 et seq., Exec. Order

No. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350.

SOURCE: Order 72, 45 FR 18919, Mar. 24, 1980, unless otherwise noted.

§ 271.901 Applicability.

This subpart implements section 109 of the NGPA and applies to a first sale of natural gas that is not covered by a maximum lawful price under section 102, 103, 104, 105, 106, 107, or 108 of the NGPA.

§ 271.902 Maximum lawful price.

The maximum lawful price, per MMBtu, for natural gas to which this subpart applies shall be the price specified for Subpart I of Part 271 in Table I of § 271.101(a).

§ 271.903 Filing requirements.

Any person who collects a price under this subpart shall file reports required by § 276.101.

§ 271.904 Special rule.

First sale of natural gas described in section 109(a)(1), (2), (3), or (4) of the NGPA are covered by this subpart only to the extent such first sales are not covered by any maximum lawful price under section 102, 103, 104, 105, 106, 107, or 108 of the NGPA.

Subpart J--[Reserved].

Subpart K--Allowances for State Severance Taxes and Certain Production-Related Costs

§ 271.1100 Applicability.

(a) General. This subpart prescribes regulations under which a price for a first sale of natural gas shall not be considered to exceed the applicable maximum lawful prices set forth in this Part if such first sale price exceeds the maximum lawful price determined under Subparts B through J of this Part to the extent necessary to recover:

(1) State severance taxes under § 271.1102; and

(2) Production-related costs allowed by rule or order of the Commission under § 271.1104.

[45 FR 53115, Aug. 11, 1980]

§ 271.1101 Definitions.

(a) Except as provided in subparagraph (b), the term "State severance tax" as used in this subpart means any severance, production, or similar tax, fee, or other levy imposed on the production of natural gas:

(1) By any State;

(2) By any Indian tribe recognized as eligible for services provided by the Secretary of the Interior to Indians; or

(3) By any political subdivision of a State if the authority to impose such tax, fee, or other levy is granted to such political subdivision under State law.

(b) The term "State severance tax" does not include any amount of tax which results from a provision of State law enacted on or after December 1, 1977, unless such provision of law is equally applicable to natural gas produced in such State and delivered in interstate commerce and to natural gas produced in such State and not so delivered.

[45 FR 53115, Aug. 11, 1980]

§ 271.1102 State severance taxes.

(a) Except as provided in paragraphs (b) and (c) of this section, the price for any first sale of natural gas shall not be considered to have exceeded the maximum lawful price applicable to that sale as set forth in this part if such first sale price exceeds the maximum lawful price to the extent necessary to recover State severance taxes borne by the seller.

(b) The maximum lawful prices prescribed under this part for interstate sales of natural gas produced from the Permian Basin area include State severance taxes in the amount of 2.6 cents for large producers and 3.05 cents for small producers. To the extent maximum lawful prices are established by reference to the Permian Basin area rate, only amounts of State severance tax in excess of those amounts already included may be considered under paragraph (a) of this section.

(c)(1) Existing tax recovery under existing intrastate and intrastate rollover contracts. Except as provided in paragraph (c)(2) of this section, the maximum lawful prices for first sales of natural gas subject to Subparts E and F of this part (relating to first sales under existing intrastate contracts and intrastate rollover contracts) are presumed to recover all State severance taxes borne by the seller, and attributable to the production of such natural gas, that were imposed by State Law enacted on or before November 9, 1978.

(2) Increased Taxes. The price for any first sale of natural gas shall not be considered to have exceeded the maximum lawful prices established in Subpart E and F of this part if such price exceeds the maximum lawful price to the extent necessary to recover the amount of increased State severance taxes borne by the seller and attributable to the production of such gas which results from an increase in the severance tax rate by State law enacted after November 9, 1978.

[45 FR 76670, Nov. 20, 1980]

§ 271.1103 Record retention.

(a) A seller in a first sale in which the price includes State severance taxes permitted under § 271.1102 shall retain a record of the sale which shall identify the seller, and shall retain such other records as are necessary to demonstrate that such seller has borne the amount of State severance taxes included in the sale price. Such records shall be preserved for at least three years from the date on which the sale occurred.

§ 271.1104 Production-related costs.

(a) General rule. To the extent provided in this section, the maximum lawful price applicable to a first sale of natural gas shall not be considered to be exceeded as a result of the addition to a first sale price of an amount necessary to recover production-related costs borne by the seller in a first sale and approved by the Commission.

(b) Special rules for certain intrastate contract gas, intrastate rollover gas and certain Alaskan gas.

(1) Certain intrastate contract gas and intrastate rollover gas. If the only maximum lawful price applicable to a sale of natural gas is determined under Subpart E or F of this part (relating to sales made under existing intrastate contracts and successors and rollovers of such contracts), then production-related costs may not be recovered under this subpart unless such costs were not allocated to the seller under the existing intrastate contract which was applicable to such gas on November 9, 1978.

(2) Certain Alaskan gas. Applications under this section for natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976 will be considered only for production-related costs described in paragraph (c)(4)(ii) of this section.

(c) Costs for which applications may be submitted. Except as provided in paragraph (b) of this section, applications will be considered by the Commission for an amount necessary to recover the following costs:

(1) [Reserved]

(2) Transportation (other than gathering) costs may be applied for.

(3) Liquefaction costs to convert an entire natural gas stream to a liquid form for the purpose of allowing cryogenic transport of the natural gas stream may be applied for; however, costs incurred to extract from the gas stream hydrocarbon constituents such as ethane, propane, butane, and natural gasolines may not be applied for.

(4)(i) Except as provided under clauses (ii) and (iii) of this subparagraph, costs of processing, treating or conditioning may be applied for to the extent they exceed the amount attributable to meeting the following standards:

(A) Total sulphur (grains per 100 cf.)--20.

(B) Hydrogen sulphide (grains per 100 cf.)--1.

(C) Water (pounds per MMcf)--7.

(D) Carbon dioxide (percent by volume)--3.

(E) Oxygen, nitrogen, dust, dirt, gum, or other impurities, in amounts in excess of which the buyer would be required to incur costs to meet pipeline requirements.

(ii) With respect to first sales of natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976, the Commission will entertain applications for costs necessary to lower the carbon dioxide content from a level of 3 percent by volume to a level of less than 3 percent by volume.

(iii) Subject to paragraph (b) of this section, the Commission will entertain applications for costs of processing, treating or conditioning natural gas with respect to first sales of natural gas to any person for use by such person.

(5) Other costs. Production-related costs, other than costs for compression, gathering, transportation, liquefaction, processing, treating or conditioning may be applied for.

(d) Certain costs not requiring application. Except as provided in paragraph (b), an application under this section need not be made for a first sale price to exceed the applicable maximum lawful price by an amount necessary to recover costs incurred for the following activities:

(1) Appalachian-Illinois Basin Areas. A gathering allowance of 1.0 cent per Mcf for all sales of natural gas made from wells located in the Appalachian-Illinois Basin Areas.

(2) Hugoton-Anadarko Area. A gathering allowance in the amounts prescribed below if delivery of the natural gas is made after substantial off-lease gathering by the producer, whether at a plant tailgate or at a central point in the field:

(i) For natural gas produced in the Panhandle and Hugoton Fields the allowance shall be 2.5 cents per Mcf; and

(ii) For gas produced from fields or reservoirs other than the Panhandle or Hugoton Fields (the "Other Fields") the allowance shall be 1.0 cent per Mcf;

(3) Other Southwest Area. A gathering allowance in the amounts listed below if the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an off-shore platform on the buyer's pipeline:

(i) For gas produced in the other Oklahoma Area, Texas Railroad District No. 9, and Northern Arkansas the allowance shall be 1.5 cents Mcf;

(ii) For gas produced in Texas Railroad District Nos. 5 and 6, Northern Louisiana, and Southern Arkansas the allowance shall be 1.0 cent per Mcf; and

(iii) For gas produced in Mississippi and Alabama the allowance shall be 1.25 cents per Mcf.

(4) Permian Basin Area. For gas produced in the Permian Basin Area, a gathering allowance of 1.5 cents per Mcf if delivery is made after substantial off-lease gathering by the producer, whether at a plant tailgate or a central point in the field.

(5) Rocky Mountain Area. For gas produced in the Rocky Mountain Area, a gathering allowance of 1.0 cent per Mcf if delivery is made to the buyer at a central point in the field, the tailgate of a processing plant, or a point on the buyer's pipeline.

(6) Southern Louisiana Area. For gas produced in the Southern Louisiana Area, a gathering allowance of 0.5 cent per Mcf if the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(7) Texas Gulf Coast Area. For gas produced in the Texas Gulf Coast Area, a gathering allowance of 0.4 cent per Mcf if the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(8) Delivery of offshore gas by the producer to an onshore area. If natural gas produced offshore is delivered onshore, at the sole cost to the producer, the allowance shall be 1.0 cent per Mcf for such offshore gas.

(9) Other allowances. In the event that a seller was authorized prior to November 9, 1978, to collect an allowance in excess of an allowance determined under clauses (1) through (8) of this paragraph, the seller may collect the allowance so authorized.

[43 FR 56551, Dec. 1, 1978; 43 FR 59482, Dec. 21, 1978, as amended by Order No. 45, 44 FR 51567, Sept. 4, 1979; 45 FR 53115, Aug. 11, 1980; 45 FR 76681, Nov. 20, 1980]

§ 271.1105 Procedures for determination and collection.

(a) Applications. Applications made to the Commission under § 271.1104 shall be under oath and shall include the following information:

(1) Identification of the maximum lawful price applicable to the first sale of the natural gas under Part 271;

(2) Documents supporting the identification of the applicable maximum lawful price, including copies of any determinations by a jurisdictional agency or the Commission or copies of applications made for such determinations;

(3) A summary of the contract provisions which contain the obligations of the parties with respect to production-related costs;

(4) If the applicant has purchased the natural gas which is the subject of an application under this paragraph, documentation of the price paid by the applicant for such gas;

(5) The specific costs sought to be recovered by the applicant and a description of the method used to compute such costs;

(6) The circumstances which make it necessary for the applicant to collect any amount in excess of the maximum lawful price provided for under Part 271; and

(7) In the case of an application made under § 271.1104(b)(1), a copy of the existing intrastate contract which was applicable to such gas on November 9, 1978, and an attestation, signed by both seller and purchaser, that it is their mutual interpretation that the costs for which application is made were not allocated to the seller under the existing intrastate contract (if the sale to which the cost is to be added is made under Subpart E), or were not allocated to the seller under the expired contract (if the sale to which the cost is to be added is made under Subpart F), as of November 9, 1978.

(b) Additional information. The Commission may, upon receipt of an application made under this section, require the submission of additional information and hold, or cause to be held, such other proceedings as it deems necessary or appropriate.

[45 FR 53115, Aug. 11, 1980; 45 FR 76681, Nov. 20, 1980]

§ 271.1106 Adjustments.

For procedures to obtain an adjustment on the grounds of special hardship, inequity, or unfair distribution of burdens, see § 1.41 of this chapter.

[45 FR 53115, Aug. 11, 1980]

I. 18 CFR 274 and 275, Natural Gas Pricing, Title 18 CFR, revised as of April 1, 1980.

1. Preamble, 18 CFR 274 and 275, Natural Gas Pricing, Subparts A, C D, and E, 44 FR 48664, August 20, 1979.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR PART 274 and 275

Natural Gas; Determinations By Jurisdictional Agencies; Commission Determinations And Commission Review Of Jurisdictional Agency Determinations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Regulations.

SUMMARY: The Federal Energy Regulatory Commission is amending and making final certain of the interim regulations published December 1, 1978, concerning determinations by Federal or State agencies having regulatory jurisdiction with respect to the production of natural gas. The regulations apply to determinations that a well is eligible for a particular maximum lawful price established by the Natural Gas Policy Act of 1978. The Commission also amends § 275.202 to reflect a change in these regulations.

EFFECTIVE DATE: August 1, 1979.

FOR FURTHER INFORMATION CONTACT:
Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100-H, 825 North Capitol Street N.E., Washington, D.C. 20426 (202) 275-4867.

Final Regulations for Subparts A, C, D, and E of Part 274 Concerning Determinations by Jurisdictional Agencies under the Natural Gas Policy Act of 1978 and Amendment to § 275.202 (Order No. 41).

Issued: August 1, 1979.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations (43 FR 56448, December 1, 1978) implementing certain sections of the Natural Gas Policy Act of 1978 (NGPA), Part 274 of the interim regulations applies to initial determinations by jurisdictional agencies that a well is eligible for a particular maximum lawful price established by the NGPA. This order amends Subparts A, C, D, and E[1] of Part 274. Subpart A applies to the jurisdictional agency determination process and the mechanism by which it gives notice of same to the Commission. Subpart C describes the procedures under which a jurisdictional agency may enter into an agreement with the Commission to waive its authority to make determinations. Subpart D provides for Commission discretion to delegate to certain State regulatory agencies the Commission's authority under Part 276 to receive filings under that part. Subpart E defines jurisdictional agency, contains a table of agencies by State, and defines Federal lands. This order also amends § 275.202 of the Final Regulations for Subpart B, Part 275, to reflect a change in that section necessitated by a change in Part 274, Subpart A.

II. Summary of Comments and Revisions

A. Subpart A. Subpart A of Part 274 relates to the procedures by which jurisdictional agencies make determinations in accordance with section 503 of the NGPA. Section 274.101 lists the categories of natural gas to which Part 274 applies.

Section 274.102 provides that a determination has been made once it is "administratively final" before the jurisdictional agency. If, for example, a State agency's decisions are normally subject to rehearing under its usual procedures, the determination is not final until the period for rehearing expires or rehearing is sought and denied.

Section 274.103 stipulates that the procedures applicable to determinations by jurisdictional agencies shall be those procedures prescribed by State law for making NGPA determinations, or for making comparable determinations. The Commission received a number of comments on this section which proposed that uniform standards be established for jurisdictional agency proceedings with respect to public notice, intervention, conduct of hearings, and so forth. We have rejected all of these suggestions because we do not believe we have the statutory authority to determine procedural rules for proceedings before the jurisdictional agencies. Section 503(c)(3) of the NGPA states:

Determinations of a Federal or State agency referred to in subsection (a)(1) shall be made in accordance with the procedures generally applicable to such agency for the making of such determinations or comparable determinations

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[1]Final regulations for Part 274, Subpart B (which prescribes the filing requirements which apply to applications for determinations) will be adopted separately, after issuance of final regulations for Subparts B, C, G, and H of Part 271.

under the provisions of Federal or State law, as the case may be, pursuant to which they exercise their regulatory jurisidction. The Commission may prescribe the form and content of filings with a Federal or State agency in connection with determinations made under this section.

The Statement of Managers indicates that questions regarding procedures followed by the jurisdictional agencies are to be reviewed directly by the State or Federal court having jurisdiction with applicable State or Federal law. (S. Rep. No. 95-1126, 95th Cong., 2nd Sess. 119 (1978)). Since Congress specifically provided that proceedings before the jurisdictional agencies were in accord with their generally applicable procedures and that review of procedures used was the province of the courts, the Commission lacks the statutory authority to prescribe the procedures suggested in the comments. In veiw of the Commission's lack of authority, comments concerning proceedings before jurisdictional agencies should be directed to those agencies.

The final regulations in § 274.104 are based on section 503(a)(2) of the NGPA, which provides that each notice of determinations shall "include such substantiation and be in such manner as the Commission may, by rule, require." Our regulations provide that a jurisdictional agency must notify the Commission within 15 days after making a determination. Notice of an affirmative determination must include: (1) A list of participants in the proceeding and persons who submitted or sought to submit written comments; (2) a statement indicating whether the matter was opposed before the jurisdictional agency; (3) the information set forth in § 274.105 as applied to the determination in question, unless the jurisdictional agency has filed a report with the Commission in accordance with § 274.105; (4) a copy of the application and a copy or description of other materials upon which the jurisdictional agency relied in the course of making the determination, together with any information which may be inconsistent with its determination; (5) the information required to be filed by the applicant under Subpart B of Part 274 or § 274.207; and (6) a statement sufficient to enable a person examining the notice to ascertain the basis for the determination, without reference to data not contained in the record.

Item (4) above differs somewhat from item (4) as it appeared in the interim regulations. The change was made in response to a comment which asserted that any information inconsistent with the agency's determination should be required to be included with the notice. In order to clarify any misunderstanding in this regard, we have amended § 274.104(a)(4) to provide that an agency must include a copy or description of both the materials on which it relied in making the determination, and any information inconsistent with the determination which came to its attention in the course of making the determination.

Item (5) above also differs somewhat from item (5) as it appeared in the interim regulations. The item formerly required, inter alia, an "affirmative finding" by the jurisdictional agency that the notice included all the information required to be filed by the applicant. After some experience with this regulation, the Commission has found that in certain cases the "affirmative finding" is made, but some of the information itself is omitted. This makes it necessary for the Commission to act without having before it the minimum information upon which to review the determination for substantial evidence. We believe that a reasonable means of dealing with such a situation is to toll the Commission's 45-day review period and to notify the agency that the notice is incomplete. Accordingly, we have amended item (5) to require that the notice from the jurisdictional agency shall include "the information required to be filed by the applicant under Subpart B of Part 274 or under § 274.207." If any of this information is not included, the Commission may, pursuant to § 275.202(b), toll the review period and notify the jurisdictional agency that the notice is incomplete.

Item (6) above is an addition to the interim regulations. It has been inserted because the Commission has found, after several months of experience in reviewing jurisdictional agency determinations, that notices submitted by the agencies are not always presented in a manner which is fully understandable to the Commission. For example, if a notice that a well qualifies under section 103 as a new, onshore production well includes a plat to establish a required fact, and the plat uses a set of unfamiliar symbols and contains no legend explaining those symbols, the Commission may not be able to ascertain the jurisdictional agency's basis for making the section 103 determination. In our review of the notice, we may be unable on the basis of the plat to find substantial evidence that the determination rests on a finding that the well meets certain well spacing requirements and is not located within an existing proration unit. Accordingly, we have added language in a new subsection § 274.104(a)(6) which requires an explanatory statement, including factual findings, which describes the basis for the determination. We have also changed § 275.202(b), (under which the Commission may notify the jurisdictional agency if a notice is incomplete) to reflect this additional language.

One comment on § 274.104 proposed that the complete record of the proceedings before the jurisdictional agency be submitted to the Commission for review, rather than a copy or description of the materials in the record. In this respect, our several months of experience in reviewing jurisdictional agency notices is

again relevant. On the basis of this experience, we have concluded that we will be able to meet our statutory obligation to review determinations by looking to the written notice submitted to the Commission by the jurisdictional agency pursuant to subparagraphs (1) through (6) of § 274.104(a). A requirement that the complete record be filed would be unduly burdensome, in that it would necessitate the copying and transmittal or large amounts of technical data for a single application.

Notice of a negative determination by a jurisdictional agency must be given to the Commission within 15 days, pursuant to the requirements of § 274.104(b). Where an applicant or any aggrieved party so requests within 15 days following the negative determination, the notice shall include all of the information required to be transmitted to the Commission when an affirmative determination is made pursuant to clauses (1) through (6) of § 274.104(a). This rule has been amended to provide that where the applicant or aggrieved party makes such a request, the jurisdictional agency shall submit the additional information within 20 (rather than 15) days after the determination has been made. This will give the agency a maximum of 20 and a minimum of 5 days in which to comply with the request.

Section 274.105 provides an alternative to the procedures prescribed in § 274.104(a)(3). If a jurisdictional agency chooses to adopt the § 274.105 option, it may file with the Commission a report in which it undertakes to make the necessary determinations and in which it describes of the procedures to be followed in making them. The agency will then be relieved of the obligation to describe its procedures in each individual case.

One commentor stated that § 274.105, along with § 274.104(a)(3), should be eliminated from the regulations because both sections assert Commission jurisdiction over jurisdictional agency procedures. In considering this comment, we note that the sections in question require that two kinds of information be submitted: (1) the filing requirements applicable to the particular section of the NGPA under which the determination is being made, and (2) an explanation or description of the procedures and rules under which the jurisdictional agency operates. With respect to item 1, the NGPA stipulates in section 503(c)(3) that "...The Commission may prescribe the form and content of filings with a Federal or State agency in connection with determinations made under this section." With respect to item 2, the regulations do not prescribe procedures; they merely require a description or explanation of those procedures. Accordingly, we do not believe that either § 274.104(a)(3) or § 274.105 asserts unlawful Commission jurisdiction over the procedures of jurisdictional agencies.

B. Subpart C. Subpart C of Part 274 implements section 503(c)(2) of the NGPA by prescribing the procedures by which a jurisdictional agency and the Commission may enter into an agreement under which the former may waive authority to the latter to make NGPA determinations.

Section 274.302 provides that an agency may file a request for waiver to the Commission, specifies the contents of such a request, and requires an agency to state the reasons for the request. If the Commission decides to enter an agreement of waiver, it may do so. The Commission may impose such terms and conditions that it deems appropriate. The provisions of § 274.303 specify the method under which a revocation or termination of the agreement shall occur.

One State filed a comment suggesting that the Commission does not have the discretion to refuse any request for a waiver. We disagree. Section 503(c)(2)(A) of the NGPA stipulates that a Federal or State agency may waive its authority to make determinations "by entering into an agreement" in accordance with subpargraph (B). Subparagraph (B), in turn, provides that any waiver may be made "only by a written agreement" between the agency and the Commission. We believe that this language provides the Commission with the discretion to agree or not to agree to a proposal for a waiver and thus to grant or refuse a request for waiver.

C. Subpart D. Subpart D of Part 274 authorizes delegation, to certain State regulatory agencies, of the Commission authority under Part 276 to receive filings from intrastate pipeline purchasers of gas sold pursuant to sections 105 and 106(b) of the NGPA.

Section 274.401(b) limits the "State agency" to which such a delegation may be made to one with jurisdiction over the rates and charges of the intrastate pipelines that would be making the required filing. One commentor asked whether the Commission has statutory authority to make a delegation to this "State agency", since such an agency is nowhere mentioned in the NGPA. In this respect, we note that section 501(c) of the NGPA provides that the Commission "may delegate to any State agency (with the consent of such agency) any of its functions with respect to sections 105, 106(b) and 109(a)(1) and (3)." (emphasis added) Accordingly, we find no merit to this comment.

Another comment proposed that the Commission refrain from exercising its statutory authority to delegate receipt of intrastate pipeline filings under Part 276. This comment asserted that the Commission should be the basic repository for these reports in order that it may be kept properly informed of the actual operations of sections 105 and 106(b). In general, while we believe it is consistent with the intent of the NGPA to shift a greater part of the total compliance role of natural gas regulation to the States, the Commission's overall responsibility to enforce the NGPA, and the fact that intra-

state sales will be regulated for the first time under the NGPA, argue in favor of the Commission's retention of this role at this particular time. Accordingly, we agree with this comment and will amend § 274.401, leaving the delegation procedure as it stands, but adding a provision which establishes that in cases where the Commission delegates to a State agency its authority to receive Part 276 filings from an intrastate pipeline purchaser, the delegation agreement shall contain terms by which the Commission will be provided with such copies of Part 276 filings as it may require.

Several producers raised an additonal issue with respect to the above-described intrastate pipeline filings. They argued that the jurisdictional agency (as defined in section 503(c) of the NGPA) should be designated as the recipient of the filings, rather than the State agency regulating intrastate pipelines. It was argued that such a rule would eliminate the possibility of a bifurcated structure's emerging in those States in which two separate State agencies could have responsibilities regarding first sales under the NGPA. We agree that this suggestion has merit in terms of consolidating NGPA information. However, we believe that it is more important that these filings be directed to the State agency as specified in § 274.401(b) in order to assist it in regulating the intrastate pipelines within its jurisdiction and to enable such agency to exercise its expertise in this area. For this reason we have not adopted the proposal.

Another comment on § 274.401 suggested that the Commission provide for delegation of authority to receive reports relating to section 109(a)(1) and (3). We note that exercise of the delegation authority in § 274.401 will operate to permit intrastate pipelines purchasing section 105 and 106(a) gas to file Part 276 reports with the appropriate State agency. However, Part 276 imposes no reporting duty on intrastate pipelines purchasing section 109 gas. For this reason section 109 has not been included within the scope of § 274.401.

In response to another comment on § 274.401, the language of the section has been amended to clarify the fact that the reports required to be filed by an intrastate pipeline should reflect sales (not reports) made pursuant to section 105 and 106(b).

D. Subpart E. Subpart E of Part 274 defines jurisdictional agency, contains a table of agencies by State, and defines Federal lands.

A comment on this subpart suggested that the Commission does not possess statutory authority to prescribe the names of State and Federal jurisdictional agencies. In response to the concern expressed in the comment, we have amended § 274.501 both to reflect the definition of jurisdictional agency contained in section 503(c) of the NGPA, and to make it clear that § 274.501(a)(2) lists the agencies which have notified the Commission of their authority to make determinations. We believe that such a listing provides useful information to persons seeking to apply for NGPA determinations.

Several State jurisdictional agencies and the Geological Survey of the Department of the Interior have notified the Commission that the list set forth in this section requires modification or correction with respect to their particular addresses. Accordingly, we are amending § 274.501(a)(2) to reflect the appropriate changes. We are also amending § 274.501(c)(2) to reflect the fact that the Osage Indian Agency retains jurisdiction over wells the surface locations of which is on lands within the boundaries of the Osage Reservation.

Several comments asked which jurisdictional agency should make the determination when a well is located on a divided-interest lease involving Federal (or Indian) and private (or State) ownership. The Commission believes that the most reasonable approach in such a case is to provide that where the divided-interest lease pertains to a drilling unit which is drained by one well, (1) the Federal jurisdictional agency shall make the determination where the majority lease interest is Federal (or Indian); (2) the State agency shall make the determination where the majority interest is private (or State); and (3) the State agency shall make the determination where the interest is divided equally. As noted below, however, the two agencies could agree to a different arrangement.

In those cases where a drilling unit is drained by two or more wells, the Federal jurisdictional agency shall make the determination if the completion location of the well in question is located on a Federal lease, and the State jurisdictional agency shall make the determination if the completion location is on a private lease. Section 274.501 has been amended to reflect this approach, although, again, the agencies could agree to a different arrangement.

Section 274.501(f) of the regulations provides that if the U.S. Geological Survey and any State jurisdictional agency enter into an agreement authorizing the State agency to make determinations with respect to wells located on Federal lands, or vice versa, the agency authorized in the agreement shall be considered the jurisdictional agency with respect to wells on the designated lands upon the filing of such agreement with the Commission.

One comment suggested that this section be deleted because the Act does not provide that one agency may delegate its jurisdiction to another. We have not made this change. Section 274.501(f) was included in the regulations to reflect the fact that an agency having regulatory jurisdiction with respect to the production of natural gas may, apart from any provision contained or not contained in the NGPA, agree to transfer or delegate such jurisdiction.

Should such an event occur, the agency designated in the agreement would become "the Federal or State agency having regulatory jurisdiction with respect to the production of natural gas." Accordingly, the Commission would be required by section 503(c)(1) of the NGPA to recognize that agency as the jurisdictional agency authorized to make determinations with respect to any wells on land covered by the agreement.

III. Public Procedures and Effective Date

The regulations in Subparts A, C, D, and E of Part 274 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, Dec. 1, 1978). For 60 days thereafter comments were received, and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA, which requires that "to the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

The amendments to Subparts A, C, D, and E of Part 274 contained in this order rest upon consideration given to the information received during the above-described notice, comment, and hearing process, as well as upon comments received via the FERC "Hot Line." The Commission finds that further notice and public procedure with respect to these rules is unnecessary. The Commission also finds that good cause exists to dispense with the publication requirements of 5 U.S.C. § 553(d)(1) in order that both jurisdictional agencies and the Commission may more readily administer their duties under the NGPA. Accordingly, Subparts A, C, D, and E of Part 274 and Subpart B of 275, as amended, are effective as final regulations immediately with regard to applications filed prior to the date of issuance of this order but for which determinations have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, 42 USC § 7107 et seq., E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Subparts A, C, D, and E of Part 274, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are issued as final regulations as set forth below, effective immediately. Subpart B of Part 275 is amended, as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary

2. Preamble, 18 CFR 274, Natural Gas Pricing, Subpart B. 45 FR 3890, January 21 1980.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 274

Final Regulations Implementing Filing Requirements Of The Natural Gas Policy Act Of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: On December 1, 1978, the Commission issued interim regulations to implement the provisions of the Natural Gas Policy Act of 1978 (NGPA) 44 FR 56448 et seq. Among those regulations was Subpart B of Part 274 which set forth filing requirements for applicants seeking well category determinations from jurisdictional agencies. On consideration of comments received since the issuance of December 1, 1978, and in light of subsequent amendments, the Commission is now amending Subpart B of Part 274. In addition, and except for those sections which deal with certain determinations for high cost natural gas priced under section 107 of the NGPA (§ 274.205(b) through (d)), Subpart B is being issued as final regulations.

EFFECTIVE DATE: February 4, 1980.

FOR FURTHER INFORMATION CONTACT:
Thomas P. Gross, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4102B, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8026, or Clarence Burris, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8106-A, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8161.

January 4, 1980.

I. Background

On December 1, 1978, the Federal Energy Commission (Commission) issued interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA) (43 FR 56448). Part 274, Subpart B of the interim regulations set forth the minimum filing requirements for applications to jurisdictional agencies for determinations of eligibility for various categories of natural gas. These categories are new natural gas and certain Outer Continental Shelf (OCS) gas (as defined in section 102 of the NGPA), natural gas from new onshore production wells (section 103) high-cost natural gas (section 107), and stripper well natural gas (section 108).

Comments were invited from interested parties on or before February 1, 1979. Timely comments were received from a number of parties representing gas producers, gas and oil pipelines, distributors of gas (including municipalities and cooperatives), oil shippers, and public interest groups. The Commission has taken into consideration these questions and comments in developing this final regulation.

Since its original issuance on December 1, 1978, Part 271 has been amended by Order No. 42 (Docket No. RM79-68, 44 FR 48180, August 17, 1979), Order No. 42-A (Docket No. RM79-68, 44 FR 69642, December 4, 1979), Order No. 43 (Docket No. RM79-72, 44 FR 49651, August 24, 1979), Order No. 43-A (Docket No. RM79-72, 44 FR 67108, November 23, 1979), Order No. 44 (Docket No. RM79-73, 44 FR 49656, August 24, 1979) and Order No. 44-A (Docket No. RM79-73, 44 FR 66783, November 11, 1979). The present order reflects these prior amendments.

II. Summary of Comments and Revisions to Part 274, Subpart B

Section 274.201 sets forth general requirements for filing applications for determinations of eligibility with jurisdictional agencies. Among other things, §§ 274.201(b) and 274.201(c) specify who may file an application for determination and who is required to sign the application. The Commission believes that any person designated by the jurisdictional agency as eligible to make filings under this subpart may also be the person who signs the application. Accordingly, § 274.201 is being amended by deleting paragraph (c) and amending § 274.201(b) to allow the person who is filing the application to sign the applications.

Section 274.202 establishes filing requirements with jurisdictional agencies for applications for determinations for new natural gas (section 102). Among other things, this section requires the applicant to file an oath statement as to certain relevant facts, depending on whether the application for determination is for a new onshore well or a new onshore reservoir. Several comments stated that the oath requirements were confusing and too stringent.

After reviewing these comments, the Commission believes that the oath and filing requirements of this section are necessary and should not be modified. Although this section requires several different oath statements, this is necessary to verify the different facts associated with different categories of natural gas. One change has been made in § 274.202. Since several of the oath statements which accompany applications for determination of new onshore wells and new onshore reservoirs are the same, these statements have been consolidated into a new paragraph (e) in § 274.202. However, these statements are still required to be filed with

the application.

Several comments suggested that the filing requirements in §§ 274.202 and 274.203 (new natural gas and certain OCS gas) and § 274. 204 (new onshore production wells) be shortened, or that Form 121 be modified to expressly list the information required to be filed. These suggestions are not being adopted. Sections 102 and 103 of the NGPA impose certain statutory conditions which must be satisfied before a well qualifies for these categories. Section 274.202 through 274.204 implement these sections of the NGPA by requiring that certain minimum information needed to make these determinations be submitted to the jurisdictional agency. In view of the stringent requirements imposed by the NGPA which must be met before a well qualifies under section 102 or 103, the Commission believes that the information required to be filed is necessary to satisfy the statutory mandate of the NGPA.

Furthermore, the Commission has considered revising Form 121 to list the filing requirements for each different category of gas and believes such revisions are unnecessary. The substantive information which must be filed with the jurisdictional agency is specifically listed in Part 274, Subpart B. Form 121 is intented to provide only general information concerning the application for determination of eligibility. This permits jurisidictional agencies to prescribe the specific format in which the information specified in Subpart B is to be submitted to the jurisdictional agency. The Commission is of the opinion that the flexibility of this approach will allow jurisdictional agencies to prescribe a format most useful for their purposes.

Section 274.202(c)(1)(iv) requires the applicant to submit a location plat which identifies the well for which the determination is sought and any other well which is producing, or produced after January 1, 1970, natural gas and which is within a 2.5 mile radius from the well for which a determination is sought. Since only wells which produced natural gas between January 1, 1970, and April 20, 1977, are relevant, § 274.202(c)(1)(iv) has been amended to require that only wells which produced natural gas during that period be identified on the location plat. A similar change is being made in § 274.202(c)(2)(iii).

Section 274.202(c)(2)(iii) (1,000 feet deeper test) requires applicants to file a location plat which includes specific identification of all marker wells within a 2.5 mile radius drawn from the well for which a determination is sought. One comment suggested that the applicant should not be required to identify marker wells if it can be shown that the completion locations for all wells within 2.5 miles are at least 1,000 feet shallower than the completion location for the subject well. This suggestion will not be adopted. If the applicant is claiming that the completion location of a new onshore well is 1,000 feet deeper than that for any marker well within a 2.5 mile radius, the record should illustrate those marker wells.

One comment suggested that marker wells which were not drilled to a depth sufficient to penetrate the reservoir into which the subject well is drilled should not be identified under the filing requirements of § 274.202. The comment misconstrues the significance of marker wells and the 1,000 feet deeper test. If the applicant is seeking a new onshore well determination pursuant to the 1,000 feet deeper test, then the applicant must show that the completion location of the new well is at least 1,000 feet deeper than the deepest completion location of each marker well within a 2.5 mile radius. Whether the marker well penetrates the reservoir into which the subject well is drilled is irrelevant. Accordingly, a marker well within the 2.5 mile radius which does not penetrate the reservoir in which the new well is completed but which is within 1,000 vertical feet of such completion location would still disqualify the new well as a new onshore well under section 102.

Section 274.202(d) establishes filing requirements for applications for determinations regarding new onshore reservoirs. One comment suggested an amendment to this section which would allow any subsequent application for determination of eligibility for wells in the same reservoir to refer to the previous application, thereby avoiding unnecessary, repetitious filings of the same information.

The Commission recognizes that unnecessary duplication of reports should be avoided. Accordingly, §§ 274.202(d)(1)(B) and 274.203(c)(2) are being added to allow an applicant to make reference to a previously filed application for determination of eligibility which contains the same information required to be filed in his current application. The applicant may refer to applications previously filed by either himself or any other applicant. However, such previously filed applications must have been filed with the jurisdictional agency with which the current application is filed. Reference may be made only to those applications upon which the jurisdictional agency has made a determination of eligibility and which are on file with the Commission. This restriction is necessary to insure that the information to which the applicant refers is available to the Commission and the jurisdictional agency during the review period. The applicant should refer to the previously filed application by the jurisdictional agency docket number, the FERC docket or control number and the API well number.

Although the Commission expects this change to eliminate the filing of repetitious information, it should be noted that any information not contained in the previously filed applica-

tion must be submitted with the current application and that each individual application must meet the substantial evidence test.

Section 274.202(d)(1)(v) requires the applicant to state under oath that he has made or caused to be made a diligent search of all records, including production, State severance tax, and royalty payment records, which are reasonably available and relevant to the determination of eligibility. Several comments suggested that applicants should not be required to search royalty payment and State severance tax records because they do not contain information material to the determination of eligibility. It was further suggested that if such a search is required, it should be limited to such records only where applicable.

The Commission believes that a search of these records is necessary because the records may contain evidence relevant to determining whether natural gas was produced in commercial quantities. However, the regulation states, and the Commission intends, that the search may be limited to records which contain information relevant to the determination of eligibility.

Sections 274.202(d)(2)(ii)(A) through (D) require the applicant to answer certain questions under oath concerning the production of natural gas in commercial quantities, and the existence of suitable facilities for the production and delivery of natural gas to a pipeline. This section was amended in Order No. 42-A (Docket No. RM79-68, 44 FR 69642, December 4, 1979). The information is designed to determine whether the natural gas from the new onshore reservoir is subject to the behind-the-pipe exclusion or the withheld gas exclusion of sections 102(c)(1)(C)(ii) or (iii) of the NGPA, respectively. This order retains the above mentioned tests issued in Order No. 42-A, but renumbers the sections so that behind-the-pipe test is contained in § 274.202(d)(2)(ii) and the withheld-gas exclusion is contained in § 274.202(d)(2)(iii). Section 274.202(d)(2)(ii)(D) has been eliminated since the above tests will determine whether the gas qualifies as new natural gas.

Section 274.203 established the filing requirements for new reservoirs on old OCS leases. Section 274.203(e)(1) through (4), now § 274.203(e)(1)(i) through (iii) and § 274.203(e)(2), established additional filing requirements for new reservoirs on old OCS leases if the reservoir was penetrated prior to July 27, 1976. In particular, §§ 274.203 (e)(1) through (3) (now renumbered as §§ 274.203 (e)(1)(i) through (iii)) require the applicant to submit the results of certain production tests and evidence which demonstrate as of the time of such tests or as of the time such evidence was obtained, that the reservoir was not capable of producing in paying or commercial quantities. Several comments stated that the filing requirements of this section changed the burden of proof in section 102(d)(4) of the NGPA with respect to the tests set forth in section 102(d)(2)(B)(i) through (iii).

The Commission believes that if any of the tests or evidence set forth in section 102(d)(2)(B)(i) through (iii) of the NGPA were performed on or before July 27, 1976, the results of such tests or evidence should be submitted by the applicant. However, if no such tests were performed and no other evidence concerning the reservoir's capability to produce in paying quantities exists on or before July 27, 1976, then the applicant should submit an oath statement to that effect. Accordingly, and in response to the above comments, §§ 274.203(e)(1)(i) through (iii) are changed to require the applicant to submit the test results and evidence listed in §§ 274.203(e)(1)(i) through (iii), to the extent such tests were performed on or before July 27, 1976. If such data is not available because such tests were not performed and no other evidence showing the well was capable of producing in paying quantities was in existence on or before July 27, 1976, the applicant must submit an oath statement to such effect.

One comment states that this oath statement had no statutory basis. The Commission believes that this statement is necessary in order to insure that none of the tests which would have generated the information listed in §§ 274.203(e)(1(i) through (iii) have been performed. Since the applicant has the burden of showing that the reservoir is a new reservoir on an old OCS lease, he must submit such a statement in order to meet this burden.

Another comment requested that the filing requirements in §§ 274.202, 274.204 and 274.205 be expanded to include certain additional information which would be helpful to the jurisdictional agency in making determinations of eligibility. The Commission declines to expand the filing requirements in these sections beyond that which is necessary for jurisdictional agencies to make a determination of eligibility. If jurisdictional agencies desire additional information for purposes of making such determinations, § 274.201(c) permits the jurisdictional agency to require the additional information if it deems appropriate.

Section 274.204 establishes the filing requirements for applications for determination of eligibility for new onshore production wells. One comment stated that the filing of a completion report as required by § 274.204(b) is unnecessary because, in some states, the drilling permit already contains the information needed for this determination.

The Commission notes that this report contains, among other things, the date on which surface drilling began, and it is needed to establish whether drilling began on or after February 19, 1977. Therefore, the Commission believes that all applicants should file this report. However, if jurisdictional agencies

find that the filing of this report is unnecessary and that another document providing the same information is available, they may submit an application for alternative filing and notice requirements under § 274.207. The Commission notes, however, that is is desirable to establish uniform filing requirements for all jurisdictional agencies. Accordingly, requests for alternative filing and notice requirements will be reviewed with care and granted only where circumstances warrent a change.

In applying for a determination for a new onshore production well, the applicant is required by § 274.204(c) to submit a location plat which identifies the well for which a determination is sought and all other wells within the state law proration unit (as defined in § 271.305(a)(2)) in which the well for which a determination is sought is located. This section is being amended to require the applicant to also identify the state law proration unit.

Section 274.205 sets forth the filing requirements for high-cost natural gas. Included in this section are the revisions made in Docket No. RM79-44 (44 FR 61950, October 27, 1979). Section 274.205 paragraphs (b), (c) and (d) will remain as interim rules until there is further action by the Commission.

Section 274.206 establishes the filing requirements for applicants seeking to establish stripper well status. Order No. 44 (Docket No. RM79-73, 44 FR 49656, August 24, 1979) amended § 274.206 by requiring the applicant to submit certain records and test results if the maximum efficient rate of flow for the well had not previously been established. The present order further amends this section by adding subparagraph (a)(3) to require the applicant to submit a copy of the results of any tests which establish a maximum efficient rate of flow.

Sections 274.206(a)(2), 274.206(a)(4)(i), 274.206(b)(3), and 274.206(d)(3) require the applicant to submit production records, tax records, or verified billing statements upon which the average production for the 90-day production period is based. The Commission believes that, in many cases, the filing of the actual records or billing statements is unnecessary and that a summary of such records or billing statements will serve the same purpose. These sections are therefore being amended to allow the applicant to submit a summary of the contents of such records or billing statements in lieu of the actual documents, but only if permitted by the jurisdictional agency's filing requirements.

Order No. 44 clarified § 271.804(a) of the interim regulations concerning the methodology for determining the rate of production from a well for which a stripper well's determination is sought. Section 271.804(a) requires an applicant to determine a well's rate of production by using the total volume of natural gas produced from the well regardless of whether the well is completed in more than one interval. In order to emphasize that production from a stripper well is based on the total volume from the well and not the production from each interval, § 274.206(a)(9) has been added to the filing requirements to require the applicant to submit production records for each completion location penetrated by the well bore.

Section 274.206(a)(7) (now renumbered as § 274.206(a)(8)) requires the applicant to submit production records for crude oil produced from the well for the 90-day production period on which the application is based. In those cases where no crude oil was produced from the well, the regulation is being amended to require an oath statement to that effect.

Section 274.206(a)(8) requires the producer to file "an inventory of the lease and production equipment." Several comments suggested that this filing should not be required until the producer submits a request for continued stripper well classification following the use of enhanced recovery techniques. It was further suggested that the Commission define the inventory of equipment essential for the filing.

The Commission agrees that the filing of this information is more relevant if the applicant claims an increase in production due to the use of enhanced recovery techniques. Accordingly, this filing requirement is being deleted from § 274.206(a). Section 274.206(c), pertaining to enhanced recovery techniques, is being amended to require the applicant to file a description of all processes and equipment which constitute enhanced recovery techniques. The applicant is also required to submit a list of the lease and production equipment used prior to the installation of the enhanced recovery techniques. The Commission intends such lists to include equipment which directly affects the production of natural gas, such as compression facilities, pumps, chokes, and intermittors, rather than a detailed inventory of all equipment used at the wellhead. The Commission anticipates that this information will provide a basis for the jurisdictional agency to determine whether increased production from the well has resulted from the implementation of recognized enhanced recovery techniques.

The Commission amended § 271.803(a) in Order No. 44 to specify that normal completion operations performed within two years of the initial completion do not qualify as recognized enhanced recovery techniques. In view of this, § 274.206(c) is now amended to require the well completion report to be filed when an applicant seeks a determination that increased production resulted from use of recognized enhanced recovery techniques.

Other comments were submitted regarding "production days" and certain other requirements which must be satisfied to qualify for stripper well status. These requirements are discussed

in Order No. 44, and in Order No. 44-A (Docket No. RM79-73). Producers should refer to these orders for further explanation of these issues.

Section 274.207 permits jurisdictional agencies to submit an application to the Commission to establish alternative filing and notice requirements. One comment suggested that this section be amended to allow for a special filing procedure for small producers. The Commission believes that this suggestion should not be adopted. First, we note that the NGPA does not exempt small producers from applying for jurisdictional agency determinations for eligibility. The filing requirements imposed by this subpart are intended to provide the jurisdictional agency with the minimum information which is needed for the jurisdictional agency to make a reliable determination of a well's eligibility for certain categories and to provide the Commission with sufficient information to determine whether the jurisdictional agency's determination of eligibility meets the substantial evidence test of section 503 of the NGPA. This information is necessary regardless of a producer's production capability. Accordingly, no special filing procedure is being established for small producers. However, if a jurisdictional agency believes that small procducers with natural gas wells within its jurisdictional region are capable of submitting the necessary information in some abbreviated fashion, it may submit an application to the Commission for such filing and notice requirements under § 274.207.

Another comment suggested that the oath statements in §§ 274.202 through 274.206 be amended to allow the applicant to file a one-time blanket affidavit with the Commission in lieu of the oath statement which must accompany each application. This suggestion is not being adopted. The Commission believes that the statement under oath is necessary for each application because it indicates that the applicant has carefully considered the application and all information contained therein.

The oath statements in §§ 274.202 through 274.206 require the applicant to state that he has no knowledge of any other information not described in the application which is inconsistent with his conclusion. One comment suggested that this be amended to require the applicant to submit all information relevant to the determination, not only information favorable to the applicant's conclusion.

The Commission believes that the regulations already require submission of all relevant information. The Commission intends this part of the oath statement to require the applicant to present not only all evidence which supports the applicant's conclusion, but also all relevant evidence which does not support his conclusion. The regulations require the applicant to submit a statement under oath that he has no knowledge of any other information not described in the application which is inconsistent with his conclusion. An important purpose of this oath statement is to insure that the applicant has searched and reported to the jurisdictional agency all information which is reasonably available and which does not support his conclusion.

Sections 274.202, 274.203, and 274,206 require the applicant to state under oath that he has searched or caused to be searched all records relevant to the determination of eligibility which are reasonably available. One comment questioned whether this search was limited to company records, state production records, or both. Other comments stated that the search should be limited to the producer's records since state records are usually not helpful and are not in good condition, or that the search should be limited to records which the producer believes might contain information relevant to the determination.

The Commission intends that all records, including company records and state records, should be searched for information which is reasonably related to the determination of eligibility. This search is needed to assure that the application for determination of eligibility is accurate and complete and that all information which is both favorable and unfavorable to the applicant is submitted to the jurisdictional agency and is available to the Commission upon review of the jurisdictional agency determination.

One comment was submitted which suggested that Form 121 be amended to provide the FERC rate schedule designation, if applicable. This suggestion will not be adopted. The rate schedule number has no bearing on a determination for eligibility. Form 121 contains the contract date which should assist interested persons in locating the rate schedule.

Form 121, item No. 6, requires the applicant to report the estimated annual production from the well for which a determination of eligibility is sought. One comment suggested eliminating this information. The commission believes that this information should be reported because it assists purchasers and third parties in determining which applications should be protested.

III. Public Procedures and Effective Date

The regulations in Part 274 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, December 1, 1978). For a period of sixty (60) days thereafter, the Commission received comments and held public hearings on the regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA. The amendments that appear in this final rule are based on the consideration given to the information

recieved during the above described notice, comment, and hearing process.

Therefore, the provisions of this part shall be effective thirty (30) days after issuance.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301 et seq.,) Department of Energy Organization Act, (42 U.S.C. 7101 et seq.); E.O. 12009, 42 FR 46267).

In consideration of the foregoing, Subpart B of Part 274, Chapter 1, of Title 18, Code of Federal Regulations, is amended as set forth below, effective 30 days from the date of issuance. These rules, as amended, are final regulations with the exception of paragraphs (b), (c) and (d) of § 274.205 which will remain as interim rules until further notice.

By the Commission.

KENNETH F. PLUMB,
Secretary

3. Regulations, 18 CFR 274, Natural Gas Pricing, Determinations by Jurisdictional Agencies, Title 18 CFR, revised as of April 1, 1980, amended by: 45 FR 24125, April 9, 1980; 45 FR 28099, April 28, 1980; 45 FR 35323, May 27, 1980; 45 FR 56046, August 22, 1980; and 45 FR 77430, November 24, 1980.

PART 274—DETERMINATIONS BY JURISDICTIONAL AGENCIES

Subpart A—General Provisions

AUTHORITY: Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, (15 U.S.C. 3301, et seq.); Department of Energy Organization Act, (42 U.S.C. 7101 et seq.); E.O. 12009, 42 FR 46267, unless otherwise noted.

Subpart A—General Provisions

SOURCE: Order 41, FR 48668, Aug. 20, 1979, unless otherwise noted.

§ 274.101 Applicability.

This part applies to determinations of jurisdictional agencies (as defined in § 274.501) made under the following subparts of Part 271:

(a) Subpart B (relating to new natural gas and certain OCS natural gas);

(b) Subpart C (relating to new, onshore production wells);

(c) Subpart G (relating to high-cost natural gas); and

(d) Subpart H (relating to stripper well natural gas).

§ 274.102 Definition of determination.

For purposes of this part and Part 275, a determination has been made by a jurisdictional agency when such determination is administratively final before such agency.

§ 274.103 Determinations by jurisdictional agencies.

A jurisdictional agency shall make determinations to which this part applies in accordance with procedures applicable to it under the law of its jurisdiction for making such determinations or for making comparable determinations.

§ 274.104 Notice to the Commission.

(a) Affirmative determinations. Within 15 days after making a determination that natural gas qualifies under this part for a maximum lawful price, the jurisdictional agency shall give written notice of such determination to the Commission. Unless alternative notice requirements under § 274.207 have been approved, such notice shall include the following:

(1) A list of all participants in the proceeding as well as any person who submitted or who sought an opportunity to submit written comments (whether or not such persons participated in the proceeding);

(2) A statement indicating whether the matter was opposed before the jurisdictional agency;

(3) The information set forth in paragraph (a)(1) through (7) of § 274.105 as applied to the determination in question, unless the jurisdictional agency has on file with the Commission a report describing its determination process under that section;

(4) A copy of the application together with a copy or description of all other materials upon which the jurisdictional agency relied in the course of making the determination, together with any information which may be

inconsistent with the determination.

(5) The information required to be filed by the applicant under Subpart B of Part 274 or under § 274.207, and in any case in which other materials in the record constitute portions of such information, a copy of those portions of the record; and

(6) An explanatory statement, including appropriate factual findings and references, which is sufficient to enable a person examining the notice to ascertain the basis for the determination without reference to information or data not contained in the notice.

(b) Negative determinations. Within 15 days after making a determination that natural gas does not qualify under this part for a maximum lawful price, the jurisdictional agency shall give written notice of such determination to the Commission, including a copy of FERC Form No. 121; except that if the applicant or any aggrieved party so requests within the 15 days following the determination, the notice shall be supplemented (within 20 days following the determination) to include all of the information specified in paragraph (a) of this section.

§ 274.105 Reports of determination process.

(a) Report. A jurisdictional agency may file with the Commission a report which states that it will take such steps as are reasonably necessary or appropriate to perform its functions under this part and which describes the method by which such agency will make determinations to which this part applies. The report shall be in narrative form and shall include:

(1) any filing requirements imposed by the jurisdictional agency in addition to those required by Subpart B of this part (including specific forms), as well as any more specific identification of documents listed as minimum requirements in Subpart B;

(2) the type of notice of filing that applicants will be required to give;

(3) the public or specific notice that will be given by the agency of filings, hearings, and determinations;

(4) the internal procedures applicable to such determinations, including specific references to the use of hearings, examiners, and formal consideration by the agency;

(5) the extent to which applicable rules permit interested parties to intervene, participate, or express views in proceedings before the agency;

(6) a description of the relevant data contained in the official records of other agencies to which the jurisdictional agency has access; and

(7) a detailed explanation of the manner in which the agency will review applications, including identification of the official records which will be examined.

(b) Change in procedures. The jurisdictional agency shall give written notice to the Commission of any change in procedures described in the report filed pursuant to this section.

(c) Public files. Reports and any changes thereto filed by the jurisdictional agency will be placed in the public files of the Commission.

Subpart B--Requirements for Filings with Jurisdictional Agencies

SOURCE: Order 65, 45 FR 3894, Jan. 21, 1980, unless otherwise noted.

§ 274.201 General requirements.

(a) Filing requirements applicable if alternative requirements are not adopted. The provisions of §§ 274.201 through 274.206 of this subpart apply to the extent not superseded by alternative filing requirements which have taken effect under §§ 274.207 and 274.208.

(b) Who may file. An application to which this subpart applies may be filed with the jurisdictional agency and signed by any person the jurisdictional agency designates as eligible to make filings with respect to the well for which the application is made.

(c) Additional information. The documents required by this subpart are the minimum required in support of a request for a determination. The jurisdictional agency may require additional support as it deems appropriate, and may more specifically identify the documents indicated as the minumum required.

(d) Notice to purchasers. Where an application for a determination is sought for natural gas for which the applicant has an identified purchaser, the application shall include a statement that the applicant has delivered or mailed a copy of the completed FERC Form No. 121 to the purchaser.

§ 274.202 New natural gas.

(a) Applications for determination. A person seeking a determination for purposes of Subpart B of Part 271 that production from a well qualifies as new natural gas shall file an application with the jurisdictional agency for a determination that:

(1) Such production is from a new OCS lease, in accordance with paragraph (b) of this section;

(2) Such production is from a new onshore well, in accordance with paragraph (c) of this section; or

(3) Such production is from a new onshore reservoir, in accordance with paragraph (d) of this section.

(b) New OCS lease. For purposes of demonstrating that natural gas is, or is to be, produced from a new OCS lease, the applicant shall file:

(1) FERC Form No. 121;

(2) A statement by the applicant under oath that the natural gas is, or is to be, produced from a new OCS lease which is a lease of submerged acreage entered into with the Secretary of the Interior on or after April 20, 1977; and

(3) A copy of the OCS lease or such other identification of the lease as the jurisdictional agency may permit.

(c) New onshore wells. An application for a determination that a well is a new onshore well may be filed under subparagraph (1) or (2) of this paragraph, or both.

(1) 2.5 mile test. For purposes of demonstrating that a new onshore well is not within 2.5 miles of any marker well, the applicant shall file:

(i) FERC Form No. 121;[1]

(ii) The well completion report;

(iii) The directional drilling survey, if the jurisdictional agency requires such a survey to be conducted;

(iv) A location plat which locates and identifies the well for which the determination is sought and any other well which produced natural gas after January 1, 1970, and before April 20, 1977, and is within the 2.5 mile radius drawn from the well for which a determination is sought;

(v) A statement by the applicant under oath, that on the basis of the results of the search and examination required by § 274.202(e), he has concluded that to the best of his information, knowledge and belief, there is no marker well within 2.5 miles of the well for which he seeks a determination;

(vi) The oath statements set forth in § 274.202(e); and

(vii) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files.

(2) 1,000 feet deeper test. For purposes of demonstrating that the completion location of a new onshore well is at least 1,000 feet deeper than the deepest completion location of each marker well within a 2.5 mile radius of the well for which a determination is sought, the applicant shall file:

(i) FERC Form No. 121;

(ii) The well completion report;

(iii) A location plat which locates and identifies the well for which the determination is sought and all wells which produced natural gas after January 1, 1970, and before April 20, 1977, within the 2.5 mile radius drawn from the well for which a determination is sought; including specific identification of all marker wells within the 2.5 mile radius drawn from the well for which a determination is sought;

(iv) A list of the deepest completion locations for all marker wells identified on the location plat;

(v) The directional drilling survey, if the jurisdictional agency requires such survey to be conducted;

(vi) A statement by the applicant, under oath, that on the basis of the results of the search and examination required by § 274.202(e), he has concluded that to the best of his information, knowledge and belief, there is no marker well within 2.5 miles of the well for which he seeks a determination which has a completion location less than 1,000 feet above the completion location of the new well; and

(vii) The oath statements set forth in § 274.202(e); and

(viii) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files.

(d) New onshore reservoir. (1) For purposes of demonstrating that production is from a new onshore reservoir, the applicant shall file:

(i) FERC Form No. 121;[1]

(ii) Geological information sufficient to support a determination that the reservoir is a new onshore reservoir.

(A) Such information shall include to the extent reasonably available to the applicant at the time the application is filed:

(1) Well logs;

(2) Bottom hole or surface pressure surveys;

(3) Well potential tests;

(4) Formation structure maps;

(5) Subsurface cross-section charts; and

(6) Gas analyses.

(B) If any of the information specified in paragraph (d)(1)(ii)(A)(1) through (6) of this section has already been filed in a previous application for determination with the same jurisdictional agency, and such application and determination of eligibility for such application are on file with the Commission, the applicant may submit, in lieu of such information, a statement identifying such information and the application by jurisdictional agency docket number, FERC docket or control number, and the API well number.

(iii) The well completion report;

(iv) The directional drilling survey if the jurisdictional agency requires such a survey to be conducted; and

(v) A statement by the applicant under oath that on the basis of the results of the search and examination required in § 274.202(e), he has concluded that to the best of his information, knowledge and belief, the natural gas to be produced and for which he seeks a determination is from a new onshore reservoir;

(vi) The oath statement set forth in paragraphs (d)(2) and (e) of this section; and

(vii) If the jurisdictional agency so requires, certified copies of records relied on by the applicant, including copies of the agen-

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[1]Filed as part of the original document.

cy's official files.

(2) The applicant, in his statement under oath required under paragraph (e) of this section, shall also answer, to the best of his information, knowledge and belief, and on the basis of the results of his search and examination, the following questions:

(i) Was natural gas produced in commercial quantities from the reservoir prior to April 20, 1977?

(ii)(A) If the question in paragraph (d)(1)(i) of this section is answered in the negative, was the reservoir penetrated before April 20, 1977, by an old well from which natural gas or crude oil was produced in commercial quantities from any reservoir?

(B) If the question in paragraph (d)(1)(ii)(A) of this section is answered in the affirmative, could natural gas have been produced in commercial quantities from the reservoir before April 20, 1977, from any old well described in paragraph (d)(1)(ii)(A) of this section?

(C) If the question in paragraph (d)(1)(ii)(B) of this section is answered in the negative, were any sales and deliveries of natural gas made from any other reservoir through any old well described in paragraph (d)(1)(ii)(A) of this section prior to April 20, 1977, and were any sales and deliveries of natural gas made from the subject reservoir through such old well on or after April 20, 1977, and before November 9, 1978?

(D) If the applicant is unable to answer both questions in paragraph (d)(1)(ii)(C) of this section in the negative, he must demonstrate that the Behind-the-Pipe Exclusion in section 102(c) (1)(C)(ii) of the NGPA does not apply by submitting the following:

(1) Proof that a final eligibility determination has been made that the subject reservoir is a new onshore reservoir by identifying such determination by the jurisdictional agency and FERC Docket number and the API well numbers, or,

(2) Evidence clearly demonstrating that the sale of production from the subject reservoir (net of royalty) through any well described in paragraph (d)(2)(ii)(A) of this section at the market price reasonably available as of April 20, 1977, could not have generated revenues sufficient to equal or exceed the sum of (i) 1.6 times the minimum incremental costs properly allocable to such production of installing cost-efficient facilities not in existence as of April 20, 1977, reasonably required to market such production, plus (ii) the minimum incremental expenses properly allocable to such production reasonably required to operate such facilities. All costs, expenses and revenues shall be determined as of April 20, 1977. The applicant shall also provide an explanation of the basis of all estimates accompanied by substantiating workpapers and such other evidence necessary to substantiate fully the conclusion that the Behind-the-Pipe Exclusion does not apply.

(iii)(A) If the natural gas is to be produced through an old well, were suitable facilities for the production and delivery to a pipeline of such natural gas in existence on April 20, 1977?

(B) If the question in paragraph (D)(2)(iii)(A) of this section is answered in the affirmative, were such suitable facilities installed to carry out sales and deliveries of natural gas under section 6 of the Emergency Natural Gas Act of 1977 or under the emergency sale authority pursuant to Opinion 699-B issued by the Federal Power Commission?

(e) Oath statements by the applicant. With each application for determination submitted under this section, the applicant shall submit a statement under oath:

(1) That the applicant has made, or has caused to be made pursuant to his instructions, a diligent search of all records (including but not limited to production, State severance tax, and royalty payment records and records of jurisdictional agency determinations) which are reasonably available and contain information relevant to the determination of eligibility;

(2) Describiing the search made, the records reviewed, the location of such records, and a description of any records which the applicant believes may contain information relevant to the determination but which he has determined are not reasonably available to him;

(3) That the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion that the well qualifies for the well category determination sought.

§ 274.203 New reservoirs on old OCS leases.

A person seeking a determination for purpose of Subpart B of Part 271 that natural gas is produced from a new reservoir on an old OCS lease (as defined in § 271.203(b)), shall file an application with the jurisdictional agency which contains the following items:

(a) FERC Form No. 121;

(b) The date the reservoir was penetrated;

(c) Geological information sufficient to support a determination that the reservoir is a new reservoir on an old OCS lease.

(1) Such information shall include to the extent reasonably available to the applicant at the time of the determination:

(i) Well logs;

(ii) Bottom hole or surface pressure surveys;

(iii) Well potential tests;

(iv) Formation structure maps;

(v) Subsurface cross-section charts;

(vi) Gas analyses;

(2) If any of the information specified in paragraph (c)(1) of this section has already been filed in a previous application for determination with the same jurisdictional agency,

and such application and a determination of eligibility for such application are on file with the Commission, the applicant may submit, in lieu of such information, a statement identifying such information and the application by jurisdictional agency docket number, FERC docket or control number, and the API well number.

(d) The well completion report;

(e) If the date of penetration of the reservoir is prior to July 27, 1976:

(1) Then to the extent such tests were performed on or before July 27, 1976;

(i) The results of any production test meeting the requirements of OCS Order No. 4 with respect to such reservoir; and

(ii) Any production capability evidence meeting the requirements of OCS Order No. 4 with respect to such reservoir; and

(iii) Any induction-electric logs, sidewall cores and core analyses, or wire line information tests with respect to such reservior; or

(2) A statement by the applicant, under oath, that no such production tests were performed and that no evidence existed on or before July 27, 1976, that the reservoir was capable of producing in paying quantities;

(f) A statement by the applicant, under oath:

(1) That the applicant has made, or has caused to be made pursuant to his instruction, a diligent search of all records (including but not limited to production and royalty payment records) which are reasonably available and contain information relevant to the determination of eligibility;

(2) Describing the search made, the records reviewed, the location of the records, and a description of any records which the applicant believes may contain information relevant to the determination but which he has determined are not reasonably available to him;

(3) That on the basis of the results of this search and examination, the applicant has concluded that to the best of his information, knowledge and belief, the natural gas for which the applicant seeks a determination is produced from an old lease on the OCS from a reservoir which was not discovered before July 27, 1976; and

(4) That he has no knowledge of any other information not described in the application which is inconsistent with his conclusion;

(g) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files.

§ 274.204 New, onshore production wells.

A person seeking a determination for purposes of Subpart C of Part 271 that a well is a new, onshore production well shall file an application with the jurisdictional agency which contains the following items:

(a) FERC Form No. 121;

(b) The well completion report;

(c) A location plat which locates and identifies the State law proration unit (as defined in § 271.305(a)(2)) and the well for which a determination is sought and all other wells within the State law proration unit in which the well for which a determination is sought is located;

(d) A statement by the applicant, under oath:

(1) That the surface drilling of the well for which he seeks a determination was begun on or after February 19, 1977;

(2) That the well satisfies any applicable Federal or State well spacing requirements;

(3) That, except as provided in paragraphs (f) and (g) of this section, the well is not within a State law proration unit (as defined in § 271.305(a)(2)):

(i) Which was in existence at the time the surface drilling of the well began;

(ii) Which was applicable to the reservoir from which such natural gas is produced; and

(iii) Which applied to any other well which either produced natural gas in commercial quantities or the surface drilling of which was begun before Febraury 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities;

(4) That on the basis of the documents submitted in the application, the applicant, has concluded that to the best of his information, knowledge and belief, the natural gas for which the applicant seeks a determination is produced from a new, onshore production well; and

(5) That the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion;

(e) If the jurisdictional agency so requires, certified copies of the records relied on by the applicant including copies of the agency's official files; and

(f) If the applicant is seeking a determination with respect to a new well drilled into an existing State law proration unit pursuant to § 271.305, the applicant must file all items required in paragraphs (a) through (e) of this section, except for the portion of the oath statement described in paragraph (d)(3) of this section and demonstrate by appropriate geological evidence and engineering data that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit.

(g) For the purposes of paragraph (d)(3)(iii) of this section, the applicant may rely on the rebuttable presumption created in § 271.305(d) unless the applicant knew that a well in the proration unit, which was plugged and abandoned prior to January 1, 1970, and has not produced natural gas on or after that date, produced natural gas in commercial quantities or, after

February 19, 1977, was capable of producing natural gas in commercial quantities.

§ 274.205 High-cost natural gas.

(a) Deep, high-cost natural gas. A person seeking a determination for purposes of Part 272 that natural gas is deep, high-cost natural gas shall file an application with the jurisdictional agency which contains the following items:

(1) FERC Form No. 121;

(2) All well completion reports for the well for which a determination is sought;

(3) The log heading together with the relevant portion of the well log or well servicing company reports or such other information which will corroborate the depth of the completion location reported in the well completion report.

(4) Directional drilling surveys, if available;

(5) A statement by the applicant, under oath, that the surface drilling of the well for which the applicant seeks a determination began on or after February 19, 1977, that the well completion location is located at a true vertical depth of more than 15,000 feet and that the applicant has no knowledge of any information not described in the application which is inconsistent with his conclusions; and

(6) If the jurisdictional agency so requires, certified copies of records relied on by the applicant, including copies of the agency's official files.

(b) Natural gas produced from geopressured brine. A person seeking a determination for purposes of Part 272 that natural gas is produced from geopressured brine shall file an application with the jurisdictional agency which contains the following items:

(1) FERC Form No. 121;

(2) The well completion report;

(3) A bottom-hole pressure test report and other information establishing the initial reservoir pressure gradient;

(4) Evidence to establish that, before production, the gas from the well was in solution in a brine aquifer with at least 10,000 parts of dissolved solids per million parts of water;

(5) A statement by the applicant, under oath, that the information establishing the initial reservoir geopressure gradient indicates a reservoir geopressure gradient in excess of 0.465 pounds, that the gas from the well was in solution in a brine aquifer with at least 10,000 parts of dissolved solids per million parts of water and that the applicant has no knowledge of any information not described in the application which is inconsistent with his conclusions; and

(6) If the jurisdictional agency so requires, certified copies of records relied upon by the applicant including copies of the agency's official files.

(c) Occluded natural gas produced from coal seams. A person seeking a determination for purposes of Part 272 that natural gas is occluded natural gas produced from coal seams shall file an application with the jurisdictional agency which contains the following items:

(1) FERC Form No. 121;

(2) The well completion report, if the gas is produced through a well bore, or a detailed description of the production process if the gas is not produced through a well bore;

(3) A radioactivity, electric or other log which will define the coal seams or, if such logs are not reasonably available, a detailed lithologic description of the gas-producing interval;

(4) Evidence to establish that the natural gas was produced from a coal seam;

(5) A statement by the applicant, under oath, that the gas was produced from a coal seam and that the applicant has no knowledge of any information not described in the application which is inconsistent with his conclusion; and

(6) If the jurisdictional agency so requires, certified copies of records relied upon by the applicant, including copies of the agency's official files.

(d) Natural gas produced from Devonian shale. A person seeking a determination for purposes of Part 272 that natural gas is produced from Devonian shale shall file an application with the jurisdictional agency which contains the following items:

(1) FERC Form No. 121;

(2) The well completion report;

(3)(i) For wells completed on or after November 1, 1979, a gamma ray log with superimposed indications of the shale base line and the gamma ray index of 0.7 over the Devonian age stratigraphic section penetrated by the well bore;

(ii) For wells completed before November 1, 1979:

(A) A gamma ray log, if reasonably available, with superimposed indications of the shale base line and the gamma ray index of 0.7 over the Devonian age stratigraphic section penetrated by the well bore; or

(B) If a gamma ray log is not reasonably available, a driller's log, or similar report, indicating the general characteristics of the strata penetrated and the corresponding depths at which they are encountered throughout the Devonian age stratigraphic section penetrated by the well bore;

(4) A sworn statement:

(i) Calculating the percentage of footage of the producing interval which is not Devonian shale as indicated by a gamma ray index of less than 0.7 if a gamma ray log described in subparagraph (3)(i) or (3)(ii)(A) has been filed or as indicated by the report described in subparagraph (3)(ii)(B);

(ii) Demonstrating that the percentage of potentially disqualifying nonshale footage is equal to or less than 5 percent of the gross

Devonian age interval; and

(iii) That the applicant has no knowledge of any information not described in the application which is inconsistent with his conclusions;

(5) A reference to a standard stratigraphic chart or text establishing that the producing interval is a shale of Devonian age; and

(6) If the jurisdictional agency so requires, certified copies of the agency's official files.

(e) Natural gas produced from designated tight formations--

(1) New tight formation gas. A person seeking a determination for purposes of Subpart G of Part 271 that natural gas is new tight formation gas shall file with the jurisdictional agency an application which contains the following items:

(i)(A) If the gas is produced from a well which qualifies as a new, onshore production well, all information required in § 274.204 (except for the item specified in paragraph (d)(1) of that section); or

(B) If the gas qualifies for new natural gas price, the information required in § 274.202 or § 274.203;

(ii) A map which locates and identifies the well for which the determination is sought as being within the designated tight formation;

(iii) The heading and pertinent portions of the well log, or a drilling report identifying the designated tight formation; and

(iv) A statement by the applicant, under oath, that:

(A) The surface drilling of the well for which a determination is sought was begun on or after July 16, 1979;

(B) The gas is being produced from a designated tight formation; and

(C) The applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion.

(2) Recompletion tight formation gas. A person seeking a determination for purposes of Subpart G of Part 271 of this chapter that natural gas is recompletion tight formation gas shall file with the jurisdictional agency an application which contains the following items:

(i) FERC Form No. 121;

(ii) The well completion report;

(iii) A map which locates and identifies the well for which the determination is sought as being within the designated tight formation;

(iv) The heading and pertinent portions of the well log, or a drilling report identifying the designated tight formation; and

(v) A statement by the applicant, under oath, that;

(A) The gas is being produced from a designated tight formation;

(B) The well was not completed for production in the designated tight formation prior to July 16, 1979; and

(C) The applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusions.

(f) Qualified production enhancement gas. A person seeking a determination for purposes of § 271.704 that natural gas is qualified production enhancement gas shall file with the jurisdictional agency an application which contains the following items:

(1) FERC Form No. 121;

(2) A detailed statement describing the production enhancement work that has been performed on the well, including the dates such work was commenced and completed, or that will be performed on the well;

(3) An itemized statement of costs incurred in performing the production enhancement work described in § 271.704(d), including copies of invoices and bills for such work or, if the work has not yet been completed, estimates of such cost;

(4) A statement estimating, for the five year period beginning from the month in which the application is filed, the units of gas production (MMBtu's) that:

(i) Would be produced from the well if the production enhancement work had been completed on the day that the application is filed; and

(ii) Would be produced from the well if the production enhancement work is not performed or had not been performed;

(5) The calculation, based on the estimates required by paragraph (f)(4) of this section, that is required by § 271.704(c)(1)(v);

(6) The renegotiated price and a copy of that portion of the sales contract that authorizes collections of such price;

(7) A statement by the applicant under oath, that:

(i) The production enhancement work is necessary, and can be reasonably expected, to enhance production;

(ii) The maximum lawful price that would be applicable but for qualification of the gas under § 271.704, does not, or will not, provide adequate incentive for the performance of the production enhancement work;

(iii) But for the availability of a price at least as high as the renegotiated price specified in subparagraph (6), the production enhancement work would not have been or will not be performed;

(iv) The production enhancement work was not commenced before May 29, 1980;

(v) To the best of the applicant's knowledge and belief, the estimates required by paragraph (f)(4) of this section are reasonable; and

(vi) The applicant has no knowledge of any other information not described in the application which is inconsistent with these statements and estimates;

(8) A statement by the purchaser, under oath, that to the best of the purchaser's knowledge or belief:

(i) There is a reasonable basis for the statements and estimates made by the applicant

pursuant to this paragraph; and

(ii) The purchaser has not knowledge of any information not described in the application which is inconsistent with such statements and estimates; and

(9)(i) If the application is based to any extent on fracturing operations described in § 271.704 (d)(5), a statement that:

(A) Describes the minimum separation between the target production zone and fresh water aquifers which are, or are expected to be, used as domestic or agricultural water supplies; and

(B) Identifies the measures that have been, or will be, taken by the applicant to protect the quality of such fresh water aquifers and to protect the intergrity of the separating strata between the target production zone and the fresh water aquifers if the fracturing operations might result in fluid communication between these formations;

(ii) The jurisdictional agency may waive the requirements of paragraph (f)(9)(i) of this section if it determines that the state has a program reasonably designed to assure that no damage will result from fracturing operations, to fresh water aquifers which are, or are expected to be, used as domestic or agricultural water supplies; and

(10) If the jurisdictional agency so requires certified copies of records upon which the applicant relied, including copies of the jurisdictional agency's official files.

[Order 65, 45 FR 3894, Jan. 21, 1980, as amended at 45 FR 13425, Feb. 28, 1980; 45 FR 56046, Aug. 22, 1980; 45 FR 77430, Nov. 24, 1980]

§ 274.206 Stripper well natural gas.

A person seeking a determination for purposes of Subpart H of Part 271 that a well either qualifies or continues to qualify as a stripper well shall file an application with the jurisdictional agency which contains the following items:

(a) Application for determination. For purposes of initially qualifying a stripper well, the applicant shall file:

(1) FERC Form No. 121;

(2) Production records, if available, and if not, tax records, if available, or verified copies of billing statements upon which the average production for the 90-day production period is based; or, if so permitted by the jurisdictional agency's filing requirements, summaries of such records or billing statements;

(3) A copy of the results of any tests which establish a maximum efficient rate of flow under § 271.807(a);

(4) Where the maximum efficient rate of flow for the well has not been established under § 271.807(a):

(i) Production records, if available, and if not, tax records, if available, or verified copies of billing statements for the 12-months ending on the last day of the 90-day production period upon which the application is based, or if so permitted by the jurisdictional agency's filing requirements, summaries of such records or billing statements; or

(ii) A copy of the results of any tests which measure the production capability of the well, or any other evidence upon which the jurisdictional agency could establish maximum efficient rate of flow.

(5) Where the determination is deferred pursuant to § 271.807(b)(1)(ii) or (b)(2), within 90 days after the last day of the deferred period, production data for the deferred period, including the 90-day production period upon which the application is based.

(6) The number of days natural gas was produced during the 90-day production period described in § 271.803(c)(2).

(7) The number of days natural gas was not produced during the 90-day production period described in § 271.803(c)(2), and

(i) A description of the state law or conservation practice, as set forth in § 271.803 (d)(2), pursuant to which the well did not produce on any such day or days, or

(ii) An explanation of any other reason the well did not produce on any such day or days.

(8) The production records for crude oil produced form the well for the 90-day production period upon which the application is based, or if no crude oil was produced from the well, a statement under oath to that effect.

(9) If the well is a multiple completion well, production records for each completion location penetrated by the well bore:

(i) For the 90-day production period on which the application is based; and

(ii) For the 12-month period on which the maximum efficient rate of flow presumption is based, if applicable.

(10) A statement under oath (i) that the applicant has made, or has caused to be made pursuant to his instructions, a diligent search of all records which are reasonably available and contain information relevant to the determination;

(ii) Describing the search made, the records reviewed, and the results of this search and examination upon which he has concluded that to the best of his information, knowledge and belief, the well qualifies as a stripper well;

(iii) That the production records, tax records, billing statements, or summaries of such records or billing statement relied upon in the application are correct; and

(iv) A statement that the applicant has no knowledge of any other information which is inconsistent with his conclusion that the well qualifies as a stripper well;

(11) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agen-

cy's official files.

(b) Notice by an operator or purchaser of an increase in production. For purpose of the notices required under § 271.805, the person filing shall include:

(1) The name and addresses of the operator and purchaser(s) with a designation of who is filing the notice;

(2) Identification of the subject well and accurate record reference to the original determination qualifying the well as a stripper well;

(3) The monthly production reports, tax records or billing statements upon which the notice is based for the period of production in question or, if so permitted by the jurisdictional agency's filing requirements, summaries of such records or billing statements;

(4) A statement of the average production per production day for the period in question;

(5) A statement that all of the information contained in the notice is true to the best of his information, knowledge and belief, and that the notice has been served on the appropriate entities specified in § 271.805(a)(3); and

(6) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files.

(c) Determination of increased production resulting from recognized enhanced recovery techniques. For purposes of a determination under § 271.805(e) that increased production resulted from the use of recognized enhanced recovery techniques, the applicant shall file:

(1) The names and addresses of the applicant and purchaser(s);

(2) An identification of the well and accurate reference to the original determination qualifying the well as a stripper well and the notice, if any, filed by a purchaser pursuant to § 271.805;

(3) The well completion report;

(4) A description of all processes used and equipment installed together with all dates of use or installation which constitute enhanced recovery techniques;

(5) An inventory of the lease and production equipment used such as compression facilities, pumps, chokes and intermittors for the well for the past 24 months or, if less, the period the well has been in production prior to the institution of recovery techniques;

(6) A statement, under oath, that to the best of his information, knowledge and belief, the information supplied and the conclusions drawn are true, that the operator has no knowledge of any information not described in the application which is inconsistent with any of his conclusions; and that the petition for recognized enhanced recovery techniques has been served on the jurisdictional agency, the Commission, and any purchaser; and

(7) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files.

(d) Designation that a well is seasonally affected. For purposes of a determination under § 271.804(d) that a well is seasonally affected, the applicant shall file:

(1) The names and addresses of the applicant and purchaser(s);

(2) An identification of the well and accurate record reference, if applicable, to the original determination qualifying the well as a stripper well and any notice filed by a purchaser pursuant to § 271.805;

(3) Production records, tax records or billing statements for a period of 24 months, including the 90-day production period which is the subject of the notice by the operator or the purchaser or, if so permitted by the jurisdictional agency's requirements, summaries of such records or billing statements;

(4) A description of the nature of the seasonal fluctuations as inferred from the date supplied;

(5) A statement, under oath, that the production records, tax records or billing statements, or summaries of such records or billing statements, if so permitted by the jurisdictional agency's filing requirements, relied upon in the application for the designation are correct; that the operator has no knowledge of any information not described in the application which is inconsistent with any of his conclusions; and that the petition for seasonally affected designation has been served on the jurisdictional agency, the Commission, and any purchaser; and

(6) If the jurisdictional agency so requires, certified copies of the records relied on by the applicant including copies of the agency's official files.

[Order 65, 45 FR 3984, Jan. 21, 1980, as amended at 15524, Mar. 11, 1980]

§ 274.207 Alternative filing and notice requirements.

(a) General. Upon written application by a jurisdictional agency pursuant to this section, the Commission may approve:

(1) Filing requirements which differ from those in §§ 274.201 through 274.206; and

(2) Notice requirements which differ from those in § 274.104;

(b) Contents of applications. Applications for approval of alternative filing or notice requirements shall include:

(1) Each requirement of this part for which an alternative is proposed;

(2) A description of the specific requirements which will replace the requirements in paragraph (b)(1) of this section, including copies of any forms to be used by the agency;

(3) The reasons for requesting approval of each alternative requirement, which may include the fact that such information is not available; and

(4) The basis for the belief that filings under the alternative filing requirements will provide substantial evidence on which the jurisdictional agency may base a determination or that notice under the alternative notice requirements will provide the Commission with an adequate basis upon which to review the determination.

(c) Commission review of applications. Upon receipt of an application pursuant to this section, the Commission shall give the public notice of such application and after review of any written comments, may issue an order approving the alternative requirements. The Commission will publish the order in the Federal Register.

(d) Effective date of alternative filing and notice requirements. (1) With respect to applications received by a jurisdictional agency after the effective date of approval of alternative filing requirements, such alternate requirements as are specified and approved in § 274.208 shall apply in lieu of the provisions of §§ 274.201 through 274.206.

(2) With respect to determinations made by a jurisdictional agency after the effective date of approved alternative notice requirements, the alternative notice requirements as are specified and approved in § 274.208 shall apply in lieu of the provisions of § 274.104 of this subpart.

(e) Termination of alternative filing and notice requirements. (1) A jurisdictional agency may, upon notice to the Commission, discontinue the use of any alternative filing or notice requirements approved under this subpart.

(2) The Commission may, after a public comment period of no less than 30 days, give notice to a jurisdictional agency that the Commission has terminated its approval of alternative filing or notice requirements, if it finds that the alternative filing or notice requirements:

(i) Are not sufficient to carry out the purpose of the NGPA; or

(ii) After notice and opportunity for hearing, the jurisdictional agency has not complied, or required compliance, with the alternative provisions.

(3) Applications for determinations received by jurisdictional agencies after notice of termination of the applicability of alternative filing requirements pursuant to this section and § 274.208 shall be subject to the filing requirements set forth in §§ 274.201 through 274.206.

(4) Notice of determinations made by jurisdictional agencies after notice of termination of the applicability of alternative notice requirements pursuant to this section and § 274.208 shall be subject to the notice requirements set forth in § 274.104.

§ 274.208 Alternative filing and notice requirements accepted by the Commission.

(a) Certain Infill Wells in the Blanco-Mesaverde and Basin-Dakota Pools in New Mexico.

(1) A person seeking a determination for purposes of Subpart C of Part 271 that an infill well in New Mexico, drilled in accordance with New Mexico Oil Conservation Division Order No. R-1670-T in the Blanco-Mesaverde pool or Order No. R-1670-V in the Basin-Dakota pool, is a new, onshore production well, shall file with the New Mexico jurisdictional agency or the Area Oil and Gas Supervisor of the United States Geological Survey, as appropriate, an application which contains, in lieu of the information specified in § 274.204, the following items:

(i) FERC Form No. 121;

(ii) The well completion report;

(iii) A location plat which locates and identifies the State law proration unit (as defined in § 271.305(a)(2)) and the well for which a determination is sought and all other wells within the State law proration unit in which the well for which a determination is sought is located;

(iv) A statement by the applicant, under oath: (A) That the surface drilling of the well for which he seeks a determination was begun on or after February 19, 1977;

(B) That the well satisfies any applicable Federal or State well spacing requirements;

(C) That the applicant has concluded that to the best of his information, knowledge and belief, the natural gas for which he seeks a determination is produced from a new, onshore production well; and

(D) That the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion.

(v) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files; and

(vi) A statement referencing New Mexico Oil Conservation Division Order No. R-1670-T if the well is located in the Blanco-Mesaverde pool or New Mexico Oil Conservation Division Order No. R-1670-V if the well is located in the Basin-Dakota pool.

(2) With respect to wells to which this section applies, receipt by the Commission of a notice of determination pursuant to § 274.104 shall be deemed to satisfy:

(i) The requirement of notice to the Commission under § 271.305(c); and

(ii) The requirement of § 271.305(b)(1) that appropriate geological and engineering data be included in the notice of determination.

(b) Certain Infill Wells in the Ignatio Blanco Field in La Plata and Archuleta Counties, Colorado and the Wattenberg Field in Adams and Weld Counties, Colorado.

(1) A person seeking a determination for purposes of Subpart C of Part 271 that an infill well in Colorado, drilled in accordance with the Colorado Department of Natural Resources, Oil and Gas Conservation Commission's Order No. 112-46, as ratified by the United States Geological Survey's Oil and Gas Supervisor for the Southern Rocky Mountain Area, in the Fruitland-Pictured Cliffs, Mesaverde or Dakota-Morrison Formations, Ignatio Blanco Field is a new, onshore production well, shall file with the Colorado jurisdictional agency or the Area Oil and Gas Supervisor of the United States Geological Survey, as appropriate, an application which contains, in lieu of the information specified in § 274.204, the following items:

(i) FERC Form No. 121;

(ii) The well completion report;

(iii) A location plat which locates and identifies the State law proration unit (as defined in § 271.305(a)(2)) and the well for which a determination is sought and all other wells within the State Law proration unit in which the well for determination is sought is located;

(iv) A statement by the applicant, under oath:

(A) That the surface drilling of the well for which he seeks a determination was begun on or after February 19, 1977;

(B) That the well satisfies any applicable Federal or State well spacing requirements;

(C) That the applicant has concluded that to the best of his information, knowledge and belief, the natural gas for which he seeks a determination is produced from a new, onshore production well; and

(D) That the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion;

(v) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files; and

(vi) A statement referencing Colorado's Oil and Gas Conservation Commission Order No. 112-46 if the well is located in the Fruitland Pictured Cliffs, Mesaverde or Dakota-Morrison formations of the Ignatio Blanco Field.

(2) A person seeking a determination for purposes of Subpart C of Part 271 that an infill well in Colorado, drilled in accordance with the Colorado Department of Natural Resources, Oil and Gas Conservation Commission's Order No. 232-20 in the "J" Sand Formation of the Wattenberg Field is a new, onshore production well, shall file with the Colorado jurisdictional agency an application which contains, in lieu of the information specified in § 274.204, the following items:

(i) The items specified in clauses (i) through (v) of subparagraph (1) of this paragraph; and

(ii) A statement referencing Colorado's Oil and Gas Conservation Commission Order No. 232-20 if the well is located in the "J" Sand Formation of the Wattenberg Field.

(3) With respect to wells to which this paragraph applies, receipt by the Commission of a notice of determination applies, receipt by the Commission of a notice of determination pursuant to § 274.104 shall be deemed to satisfy:

(i) The requirement of notice to the Commission under § 271.305(c); and

(ii) The requirement of § 271.305(b)(1) that appropriate geological and engineering data be included in the notice of determination.

(c) Certain Infill Wells in the Sussex and Shannon reservoirs in the Spindle Field and in the Sussex reservoir in the Hambert Field in Adams and Weld Counties, Colorado.

(1) A person seeking a determination for purposes of Subpart C of Part 271 that a second well drilled in accordance with the Colorado Department of Natural Resources' Oil and Gas Conservation Commission's Order Nos. 304-5, 250-12, 250-14, 250-16, 250-17, 250-19, 250-20, 250-21, and 250-23 in the Sussex and Shannon reservoirs in the Spindle Field and in the Sussex reservoir in the Hambert Field in Adams and Weld Counties, Colorado is a new, onshore production well, shall file with the Colorado jurisdictional agency an application which contians, in lieu of the information specified in § 274.204, the following items:

(i) FERC Form No. 121;

(ii) The well completion report;

(iii) A location plat which locates and identifies the State law proration unit (as defined in § 271.305(a)(2)) and the well for which a determination is sought and all other wells within the State Law proration unit in which the well for which a determination is sought is located;

(iv) A statement by the applicant, under oath:

(A) That the surface drilling of the well for which he seeks a determination was begun on or after February 19, 1977;

(B) That the well satisfies any applicable Federal or State well spacing requirements;

(C) That the applicant has concluded that to the best of his information, knowledge and belief, the natural gas for which he seeks a determination is produced from a new, onshore production well; and

(D) That the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion;

(v) If the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files; and

(vi) A statement referencing Colorado's Oil and Gas Conservation Commission's Order Nos. 304-5, 250-12, 250-14, 250-16, 250-17, 250-19, 250-21, or 250-23 as appropriate.

(2) With respect to wells to which this paragraph applies, receipt by the Commission of a notice of determination pursuant to § 274.104 shall be deemed to satisfy:

(i) The requirement of notice to the Commission under § 271.305(c); and

(ii) The requirement of § 271.305(b)(1) that appropriate geological and engineering data be included in the notice of determination.

(Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Department of Energy Organization Act, 42 U.S.C. 7107, et seq.; Exec. Order No. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. 3301, et seq.)

[Order 66, 45 FR 3900, Jan. 21, 1980, as amended at 45 FR 12411, Feb. 26, 1980]

[45 FR 35323, May 27, 1980]

Subpart C--Waivers

SOURCE: Order 41, 44 FR 48668, Aug. 20, 1979, unless otherwise noted.

§ 274.301 Applicability.

This subpart contains the procedures by which jurisdictional agencies and the Commission may enter into agreements under which jurisdictional agencies waive to the Commission authority to make the determinations set forth in Subpart A of this part.

§ 274.302 Requests for waiver.

(a) General. A jurisdictional agency may file with the Commission a request to enter into a written agreement waiving, in whole or in part, the authority of the jurisdictional agency to make determinations pursuant to Subpart A of this part.

(b) Contents of requests. Requests filed pursuant to this section shall include:

(1) The name of the jurisdictional agency·

(2) Each class of determination for which a waiver is sought;

(3) The reasons the jurisdictional agency believes a waiver is necessary; and

(4) The length of time any waiver is to remain in effect.

(c) Commission action on requests. After consideration of any request under this section, the Commission may execute a written agreement including:

(1) Provision that upon written acceptance of the agreement by the jurisdictional agency, the Commission, in lieu of such agency, will make the determinations waived in the agreement, and

(2) Any terms and conditions the Commission deems appropriate with respect to such waiver, including the date on which the waiver shall terminate; and

(3) The effective date of the waiver.

§ 274.303 Termination or revocation of agreements.

Agreements pursuant to this subpart shall remain in effect until public notice of the following is given by the Commission:

(a) Expiration. Notice that the agreement of waiver has expired pursuant to a term or condition of the waiver agreement;

(b) Termination: Notice that the Commission has received written notice from the jurisdictional agency that such agency terminates the agreement as of a specific date and assumes the authority to make determinations under Subpart A of this part; or

(c) Revocation: Notice that the Commission has revoked the agreement pursuant to a term or condition of the waiver agreement.

§ 274.304 Notice.

The Commission shall cause public notice to be made of agreements of waiver and of any termination or revocation of a waiver.

Subpart D--Delegations to State Agencies

SOURCE: Order 41, 44 FR 48669, Aug. 20, 1979, unless otherwise noted.

§ 274.401 Delegation of authority to receive certain reports.

(a) Delegation. The Commission may delegate to a State agency the authority to receive the reports required by §§ 276.102(d) and 276.103(d) to be filed by an interastate pipeline pursuant to sales made under sections 105 and 106(b) of the NGPA.

(b) State agency. A delegation pursuant to this section shall be made only to a State agency with jurisdiction over the rates and charges of the intrastate pipelines required to make filings under §§ 276.102(d) and 276.103(d).

(c) Terms of the delegation. If a delegation is made under paragraph (a) of this section the Commission and the State agency shall execute a delegation agreement containing such terms and conditions as the parties deem appropriate, including the manner in which the Commission will be provided with such copies of the reports as it may require. Notice of the delegation agreement shall be published in the Federal Register.

Subpart E--Identification of State and Federal Jurisdictional Agencies

SOURCE: Order 41, 44 FR 48669, Aug. 20, 1979, unless otherwise noted.

§ 274.501 Jurisdictional agency.

(a) Definition. Except as provided in paragraph (b), "jurisdictional agency" means:

(1) With respect to a well the surface location of which is on the OCS, the Federal or State agency having regulatory jurisdiction with respect to the production of natural gas. The following agencies have notified the Commission of their authority in this regard.

(i) For OCS wells located in the Gulf Coast Region: Area Oil and Gas Supervisor, Suite 336, 3301 N. Causeway Blvd., Metairie, La. 70010.

(ii) For OCS wells located in the Atlantic Region: Area Oil and Gas Supervisor, Atlantic OCS Operations, Suite 204, 1725 K Street, N.W., Washington, D.C. 20244.

(iii) For OCS wells located offshore Alaska: Area Oil and Gas Supervisor, P.O. Box 259, Suite 109, 800 A Street, Anchorage, AK 99510.

(iv) For OCS wells located offshore California: Area Oil and Gas Supervisor, 7211 Federal Building, 300 North Los Angeles Street, Los Angeles, CA 90012.

(2) With respect to a well the surface location of which is on lands within the boundaries of a State (including Federal lands and offshore State lands), the Federal or State agency having regulatory jurisdiction with respect to the production of natural gas. The following agencies have notified the Commission of their authority in this regard:

State in which well is located	Jurisdictional agency for wells on— Federal lands	Other lands
Alabama	Area Oil and Gas Supervisor, Suite 204, 1725 K St., N.W., Washington, D.C. 20006.	Oil and Gas Supervisor, State Oil and Gas Board, Drawer O, University, AL 35486.
Alaska	Area Oil and Gas Supervisor, P.O. Box 259, Suite 109, 800 A Street, Anchorage, AK 99510.	Oil and Gas Conservation Commission, 3001 Porcupine Drive, Anchorage, AK 99501.
Arizona	Area Oil and Gas Supervisor, P.O. Box 26124, 505 Marquette Ave., N.W., Albuquerque, NM 87125.	Oil and Gas Conservation Commission, Suite 420, 1645 W. Jefferson, Phoenix, AZ 85007.
Arkansas	Area Oil and Gas Supervisor, 6136 E. 32nd Place, Tulsa, OK 74135.	Oil and Gas Commission, A Division of the Arkansas Dept. of Commerce, 314 East Oak, El Dorado, AR 71730.
California	Area Oil and Gas Supervisor, 7211 Federal Bldg., 300 N. Los Angeles Street, Los Angeles, CA 90012.	Department of Conservation, Division of Oil and Gas, 1416 Ninth St., Rm. 1316, Sacramento, CA 95814.
Colorado (except for the west ranges of the New Mexico Principal Meridian).	Area Oil and Gas Supervisor, P.O. Box 2859, 2002 Federal Building and Post Office, Casper, WY 82602.	Oil and Gas Conservation Commission, 1313 Sherman Street, Rm. 721, Denver, CO 80203.
(or)		
Colorado (only the west ranges of the New Mexico Principal Meridian).	Area Oil and Gas Supervisor, P.O. Box 26124, 505 Marquette Ave., N.W., Albuquerque, NM 87125.	
Florida	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Admin. of Oil and Gas, Bureau of Geology, Dept. of Natural Resources, 903 W. Tennessee St., Tallahasse, FL 32304.

State in which well is located	Jurisdictional agency for wells on— Federal lands	Other lands
Georgia	Area Oil and Gas Supervisor, Suite 204, 1725 K St., N.W., Washington, D.C. 20006.	Dept. of Natural Resources, Geologic & Water Resources Division, 19 Martin Luther King Drive, S.W., Atlanta, GA 30334.
Idaho	Area Oil and Gas Supervisor, 7211 Federal Bldg., 300 N. Los Angeles Street, Los Angeles, CA 90012.	Idaho Public Utilities Commission, Statehouse Mail, Boise, ID 83720.
Illinois	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Dept. of Mines and Minerals, Oil and Gas Division, 704 Stratton Office Building, 400 S. Spring Street, Springfield, IL 62706.
Indiana	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Dept. of Natural Resources, Oil and Gas Divison, 606 State Office Bldg., 100 N. Senate Ave., Indianapolis, IN 46204.
Kansas	Area Oil and Gas Supervisor, 6136 East 32nd Place, Tulsa, OK 74135.	Corporation Commission, State Office Building, Topeka, KS 66612.
Kentucky	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Dept. of Mines and Minerals, Oil and Gas Division, Box 680, Lexington, KY 40501.
Louisiana	Area Oil and Gas Supervisor, 6136 East 32nd Place, Tulsa, OK 74135.	Office of Conservation, Box 44275, Baton Rouge, LA 70804.
Maryland	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Energy and Coastal Zone Administration, Dept. of Natural Resources, Tawes State Office Bldg., Annapolis, MD 21404.
Michigan	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Dept. of Natural Resources, Box 30028, Lansing, MI 48909.
Mississippi	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	State Oil and Gas Board, Box 1332, Jackson, MS 39205.
Montana	Area Oil and Gas Supervisor, P.O. Box 2859, 2002 Federal Bldg. and Post Office, Casper, WY 82602.	Oil and Gas Conservation Div., Dept. of Natural Resources and Conservation, 2535 St. Johns Ave., Billings, MT 59102, or P.O. BOX 217, Helena, MT 59601.
Nebraska	Area Oil and Gas Supervisor, P.O. Box 2859, 2002 Federal Bldg. and Post Office, Casper, WY 82602.	Oil and Gas Conservation Commission, Box 399, Sidney, NE 69162.
Nevada	Area Oil and Gas Supervisor, 7211 Federal Bldg., 300 N. Los Angeles Street, Los Angeles, CA 90012.	Dept. of Conservation and Natural Resources, Div. of Mineral Resources, Capitol Complex, 201 S. Fall St., Carson City, NV 89710.

State in which well is located	Jurisdictional agency for wells on— Federal lands	Other lands
New Mexico	Area Oil and Gas Supervisor, P.O. Box 26124, Marquette Ave., N.W., Albuquerque, NM 87125.	Dept. of Energy and Minerals, Oil Conservation Divison, Box 2088, Santa Fe NM 87501.
New York	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Dept. of Environmental Conservation, Bureau of Mineral Resources, 50 Wolf Road, Albany, NY 12233.
North Carolina	Area Oil and Gas Superviosr, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Dept. of Natural Resources and Community Development, 512 N. Salisbury Street, Raleigh, NC 27611.
North Dakota	Area Oil and Gas Supervisor, P.O. Box 2859, 2002 Federal Bldg. and Post Office, Casper, WY 82602.	Geological Survey, University Station, Grand Forks, ND 58202.
Ohio	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W. Washington, D.C. 20006.	Ohio Department of Natural Resources, 1932 Belcher Drive, Fountain Square, Columbus, OH 43224.
Oklahoma (except the Osage Reservation).	Area Oil and Gas Supervisor, 6136 East 32nd Place, Tulsa, OK 74135.	Corporation Commission, Jim Thorpe Building, Oklahoma City, OK 73105.
(or)		
Oklahoma (Only the Osage Reservation).	Superintendent, Osage Indian Agency, Bureau of Indian Affairs, U.S. Dept. of the Interior, Pawhuska, OK 74056.	
Oregon	Area Oil and Gas Supervisor, 7211 Federal Bldg., 300 N. Los Angeles Street, Los Angeles, CA 90012.	Dept. of Geology and Mineral Industries, 1069 State Office Bldg., Portland, OR 97201.
Pennsylvania	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Department of Environmental Resources, Div. of Oil and Gas Regulation, 1205 Kossman Bldg., 100 Forbes Ave., Pittsburgh, PA 15222.
South Carolina	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	South Carolina Public Service Commission, P.O. Drawer 11649, Columbia, SC 29211.
South Dakota	Area Oil and Gas Supervisor, P.O. Box 2859, 2002 Federal Bldg. and Post Office, Casper, WY 82602.	Geological Survey, Science Center University, Vermillion, SD 57069.
Tennessee	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	State Oil and Gas Board, G-5 State Office Bldg., Nashville, TN 37219.
Texas (East of the 100th Meridian).	Area Oil and Gas Supervisor, 6136 East 32nd Place, Tulsa, OK 74135.	Railroad Commission, Drawer 12967, Austin, TX 78711.
(or)		
Texas (West of the 100th Meridian).	Area Oil and Gas Supervisor, P.O. 26124, 505 Marquette Ave., N.W. Albuquerque, NM 87125.	

State in which well is located	Jurisdictional agency for wells on-- Federal lands	Other lands
Utah (except San Juan County) (or)	Area Oil and Gas Supervisor, P.O. Box 2859, 2002 Federal Bldg. and Post Office, Casper, WY 82602.	Div. of Oil, Gas and Mining, Utah Department of Natural Resources, 1588 West North Temple, Salt Lake, UT 84116.
Utah (only San Juan County)	Area Oil and Gas Supervisor, P.O. Box 26124, 505 Marquette Ave., N.W., Albuquerque, NM 87125.	
Virginia	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Div. of Mines and Quarries, P.O. Drawer V, Big Stone Gap, VA 24219.
Washington	Area Oil and Gas Supervisor, 7211 Federal Bldg., 300 N. Los Angeles Street, Los Angeles, CA 90012.	Oil and Gas Supervisor, Dept. of Natural Resources, Olympia, WA 98504.
West Virginia	Area Oil and Gas Supervisor, Suite 204, 1725 K Street, N.W., Washington, D.C. 20006.	Oil and Gas Division, Dept. of Mines, State Capitol, Charleston, WV 25305.
Wyoming	Area Oil and Gas Supervisor, P.O. Box 2859, 2002 Federal Bldg. and Post Office, Casper, WY 82602.	Oil and Gas Conservation Commission, Box 2640, Casper, WY 82602.

(b) Waiver. In the case of any determination to which a waiver made under Subpart C of Part 274 is applicable, "jurisdictional agency" means the Commission.

(c) Federal lands. For purposes of this section, "Federal lands" means:

(1) All lands leased under:

(i) The Mineral Lands Leasing Act, as amended, 30 U.S.C. §§ 181 et seq.; and

(ii) The Mineral Leasing Act for Acquired Lands, as amended, 30 U.S.C. 351 et seq.;

(2) All Indian lands which are under the supervision of the United States Geological Survey (30 CFR Part 221); and

(3) All Indian lands which are under the supervision of the Osage Indian Agency, Bureau of Indian Affairs, U.S. Department of the Interior.

(d) Divided-interest leases. Unless an agreement under paragraph (f) of this section provides otherwise, where a well is located on a divided-interest lease involving Federal (or Indian) and private (or State) ownership:

(1) The Federal jurisdictional agency shall make the determination where the majority lease interest is Federal (or Indian);

(2) The State jurisdictional agency shall make the determination where the majority lease interest is private (or State); and

(3) The State jurisdictional agency shall make the determination where the lease interest is divided equally.

(e) Drilling units. Unless an agreement under paragraph (f) of this section provides otherwise, where a drilling unit is drained by two or more wells, the Federal jurisdictional agency shall make the determination if the completion location of the well in question is located on a Federal (or Indian) lease, and the State jurisdictional agency shall make the determination if the completion location of the well in question is located on a private (or State) lease.

(f) Agreements. If the United States Geological Survey and any State jurisdictional agency enter into an agreement authorizing such determinations under Subpart A of this part with respect to wells located on Federal lands, or authorizing the U.S. Geological Survey to make such determinations with respect to wells located on State lands, such agreement shall be filed with the Commission. Upon the filing of such an agreement the agency so authorized in the agreement shall be considered the jurisdictional agency with respect to wells on the designated lands to the extent provided in the agreement.

4. Regulations, 18 CFR 275, Commission Determinations and Review of Jurisdictional Agency Determinations, Title 18 CFR, revised as of April 1, 1980.

PART 275--COMMISSION DETERMINATIONS AND REVIEW OF JURISDICTIONAL AGENCY DETERMINATIONS

Subpart A--[Reserved]

Subpart B--Procedure for Commission Review of Jurisdictional Agency Determinations

Subpart A--[Reserved]

Subpart B--Procedure for Commission Review of Jurisdictional Agency Determinations

§ 275.201 Publication of notice from jurisdictional agency.

Upon receipt of notice of determination by a jurisdictional agency under § 274.104, the Commission shall publish notice of such determination in the Federal Register. Such notice shall include:

(a) The date on which the jurisdictional agency notice was received;

(b) Certain information contained in FERC Form No. 121;

(c) A statement that the application and a copy or description of other materials in the record on which such determination was made is available for inspection, except to the extent the material is treated as confidential under § 275.206, at the offices of the Commission; and

(d) A statement that persons objecting to the final determination may, in accordance with this subpart, file a protest with the Commission within 15 days after the publication.

(Natural Gas Act, as amended, 15 U.S.C. 717 et seq., Energy Supply and Environmental Coordination Act (15 U.S.C. 791, et seq.; National Gas Policy Act of 1978, Pub. L. 95-621 Stat. 3350; Department of Energy Organization Act Pub. L. 95-91, E.O. 12009, 42 FR 46276)

[43 FR 56608, Dec. 1, 1978, as amended at 44 FR 34477, June 15, 1979]

§ 275.202 Commission review of final determinations.

(a) Review by Commission. Except as provided in paragraphs (b), (c) and (d) of this section, a determination submitted to the Commission by a jurisdictional agency shall become final 45 days after the date on which the Commission received notice of the determination, unless within the 45 day period, the Commission:

(1) Makes a preliminary finding that:

(i) The determination is not supported by substantial evidence in the record on which the determination was made; or

(ii) The determination is not consistent with information which is contained in the public records of the Commission and which was not part of the record on which the jurisdictional agency made the determination; and

(2) Issues written notice of such preliminary finding, including the reasons for the preliminary finding. Copies of the written notice will be sent to the jurisdictional agency which made the determination, to the persons identified in the notice under § 274.104 of such determination, and to any persons who have filed a protest.

(b) Incomplete notice. Notwithstanding the provisions of paragraph (a) of this section, the 45-day period for Commission review of a determination shall not begin if:

(1) The notice forwarded to the Commission pursuant to Subpart A of Part 274 does not contain all the material information required in § 274.104(a)(4), (5), and (6).

(2) The Commission notifies the jurisdictional agency, the purchaser and the parties to the proceeding before the jurisdictional agency, within 45 days after the date on which the Commission receives notice of the determination, that the notice is incomplete.

(c) Withdrawal of Notice. (1) The jurisdictional agency may withdraw a notice of determination by giving notice as specified in paragraph (c)(2) of this section at any time prior to the issuance of a final order with respect to such determination under paragraphs (g)(1) and (g)(2) of this section, or at any time prior to the date such determination becomes final under paragraphs (a) or (g)(4) of this section. Such notice shall include the jurisdictional agency's reasons for the withdrawal.

(2) Withdrawal of a notice of determination shall take effect at such time as the jurisdictional agency has notified the Commission, the parties to the proceeding before the agency, and the purchaser of such withdrawal.

(3) Withdrawal of a notice of determination shall nullify such notice of determination.

(d) Withdrawal of Application. (1) An applicant may withdraw an application for a determination which is before the Commission by giving notice as specified in paragraph (d)(2) of this section at any time prior to the

issuance of a final order with respect to such determination under paragraphs (g)(1) and (g)(2) of this section, or at any time prior to the date such determination becomes final under paragraphs (a) or (g)(4) of this section.

(2) Withdrawal of an application shall take effect at such time as the applicant has notified the Commission, the jurisdictional agency and the purchaser.

(3) Withdrawal of an application shall nullify such application and the notice of determination of such application.

(4) The applicant's right to make interim collections under Part 273 of this Chapter shall cease and the refund obligations of Part 273 of this chapter shall begin when the withdrawal takes effect under this paragraph.

(e) Public notice. The Commission shall publish notice of the preliminary findings in the Federal Register and shall post the notice in its Office of Public Information. The notice shall set forth the reasons for the preliminary finding.

(f) Procedures following notice of preliminary finding. Any State or Federal agency or any person may, within 30 days after issuance of the preliminary finding, submit written comments and request an informal conference with the Commission staff. Any jurisdictional agency, any State agency and any person receiving notice under paragraph (a)(2) may request an informal conference with the Commission staff. All timely requests for conferences will be granted. Notice of, and permission to attend, such conferences will be given to persons identified in paragraph (a)(2) of this section, may request an informal conference with the Commission staff. All timely requests for conferences will be granted. Notice of, and permission to attend, such conferences will be given to persons identified in paragraph (a)(2) of this section, and to State or Federal agencies or persons who submitted comments under this paragraph.

(g) Final orders. (1) In any case in which a protest was filed with the Commission pursuant to this subpart and a preliminary finding was issued, the Commission shall issue a final order within 120 days after issuance of the preliminary finding.

(2) In any case in which no protest was filed with the Commission pursuant to this subpart, and a preliminary finding was issued, the Commission may issue a final order within 120 days after issuance of the preliminary finding.

(3) A final order issued under paragraphs (g)(1) or (2) of this section shall either affirm, reverse, or remand the determination of the jurisdictional agency. Such order shall state the specific basis for the Commission's action. Notice of the issuance of such order shall be given to the jurisdictional agency, to participants in the proceeding before the jurisdictional agency, and to participants in the proceeding before the Commission under paragraph (f) of this section and under § 275.203.

(4) In the event that the Commission fails to issue a final order within 120 days after issuance of the preliminary finding, the determination of the jurisdictional agency shall become final.

(Natural Gas Act, as amended, 15 U.S.C. 717, et seq.; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, et seq.; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; 15 U.S.C. 3301-3342, Department of Energy Organization Act, Pub. L. 95-91, 42 U.S.C. 7107 et seq.; E.O. 12009, 42 FR 46267)

[43 FR 56608, Dec. 1, 1978, as amended at 44 FR 34477, June 15, 1979; Order 41, 44 FR 48671, Aug. 20, 1979; 44 FR 66789, Nov. 21, 1979]

§ 275.203 Protests to the Commission.

(a) Who may file. Any person may file a protest with the Commission with respect to a determination of a jurisdictional agency within 15 days after the publication of notice of that determination pursuant to §275.201 of this subpart.

(b) Grounds. Protests may be based only on the grounds that the final determination is:

(1) Not supported by substantial evidence;

(2) Not consistent with information which is contained in the public records of the Commission and which was not part of the record on which the determination was made;

(3) Not consistent with information submitted with the protest for inclusion in the public records of the Commission, which information was not part of the record on which the determination was made; or

(4) Not based on an application which complied with the filing requirements set forth in Subpart B of Part 274, or alternative filing requirements approved pursuant to § 274.207.

(Natural Gas Act, as amended, 15 U.S.C. 717, et seq.; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, et seq.; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

[43 FR 56603, Dec. 1, 1978, as amended at 44 FR 34477, June 15, 1979]

§ 275.204 Contents of protests to the Commission.

Each protest shall include:

(a) An identification of the determination protested;

(b) The name and address of the person filing the protest;

(c) A statement of whether or not the person filing the protest participated in the proceeding before the jurisdictional agency, and if not, the reason for his nonparticipation;

(d) A statement of the effect the determination will have on the protestor;

(e) A statement of the precise grounds under § 275.203 for the protest, and all supporting documents or references to any information relied on which is in the record on which the determination is based or is in or to be inserted in the public files of the Commission; and

(f) A statement that the protestor has served, in accordance with §§ 1.17 and 1.51 of this chapter, a copy of the protest together with all supporting documents on the jurisdictional agency and all persons listed in the notice of determination pursuant to § 274.104(a)(1) of this subchapter.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350)

[43 FR 56603, Dec. 1, 1978, as amended at 45 FR 17131, Mar. 18, 1980]

§ 275.205 Procedure for reopening determinations.

(a) Grounds. At any time subsequent to the time a determination becomes final pursuant to this subpart, the Commission, on its own motion, or in response to a petition filed by any person aggrieved or adversely affected by the determination, may reopen the determiantion if it appears that:

(1) In making the determination, the Commission or the jurisdictional agency relied on any untrue statement of material fact; or

(2) There was omitted a statement of material fact necessary in order to make the statements made not misleading, in light of the circumstances under which they were made to the jurisdictional agency or the Commission.

(b) Contents of petition. A petition to reopen the determination proceedings shall contain the following information, under oath:

(1) The name and address of the person filing the petition;

(2) The interest of the petitioner in the outcome of the determination proceeding;

(3) The statement of material fact that is alleged to be untrue or omitted;

(4) A statement explaining why the outcome of the determination proceeding would have been different had the statement or omission not occured; and

(5) Copies of all documents relied on by the petitioner, or references to such documents if they are contained in the public files of the Commission.

(c) Procedures after reopening. In the event the Commission reopens a determination pursuant to this section it shall:

(1) Give notice to the jurisdictional agency and all persons who participated, before both that agency and the Commission, in the proceedings resulting in the determination in question;

(2) Permit the jurisdictional agency and other persons receiving notice pursuant to subparagraph (1) to submit whatever documentary evidence such agency or persons deem relevant; and

(3) Take such other action or hold or cause to be held such proceedings as it deems necessary or appropriate for a full disclosure of the facts.

(d) Final order of Commission. Within 150 days after issuance of the notice under paragraph (c)(1) of this section, the Commission shall issue a final order. If the Commission finds that the grounds referred to in paragraph (a) of this section exist, it shall vacate the determination, and if appropriate, order refund or other action. The right to collect the previously determined maximum lawful price shall terminate on the date of the order vacating the determination.

(Natural Gas Act, as amended, 15 U.S.C. 717, et seq.; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, et seq.; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

[43 FR 56603, Dec. 1, 1978, as amended at 44 FR 34477, June 15, 1979]

§ 275.206 Confidentiality.

(a) Except as provided in paragraph (b), the Commission will accord confidential protection to, and not disclose to the public, any information submitted to the Commission by a jurisdictional agency under § 274.104(a)(4), if:

(1) The jurisdictional agency, on its own motion or on request of the applicant, afforded such information confidential treatment before the jurisdictional agency; and

(2) The agency order or the applicant's request stated grounds for confidential treatment which fall within one of the exemptions described in paragraphs (1) through (9) of 5 U.S.C. 552(b).

(b) Upon receipt of a request for disclosure of information treated as confidential under paragraph (a), the Commission will determine in accordance with 5 U.S.C. 552 whether the information is exempt under 5 U.S.C. 552(b). If it determines the information is not exempt, the information will be made public. If it determines that the information is exempt, the Commission will not make it public unless the Commission determines that its conduct of the proceeding to review the jurisdictional agency determination requires making

such information available to the public or to particular parties, subject to such conditions (including a protective order) as the Commission may prescribe. Before making any information public under this paragraph, the Commission shall provide at least 5 days notice to the person who submitted the information. Such notice shall be sent to telegraph.

(Natural Gas Act, as amended, 15 U.S.C. 717, et seq.; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, et seq.; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

[43 FR 56603, Dec. 1, 1978, as amended at 44 FR 34478, June 15, 1979; 45 FR 17131, Mar. 18, 1980]

J. 30 CFR 250, Oil and Gas and Sulphur Operations in the Outer Continental Shelf, Title 30 CFR, revised as of July 1, 1979, amended by: 44 FR 53693, September 14, 1979; 44 FR 61892, October 26, 1979; 45 FR 15142-44, March 7, 1980; 45 FR 20464-65, March 28, 1980; 45 FR 29285, May 2, 1980; 45 FR 37816-18, June 5, 1980; 45 FR 43256, June 26, 1980; 45 FR 74471, November 10, 1980; and 45 FR 81563, December 11, 1980.

1. Preamble, 30 CFR 250, Oil and Gas and Sulphur Operations; excluding Sections 250.34 Exploration, Development, and Production Activities; 250.50-51, Unitization; and 250.57, Air Quality; 44 FR 61886, October 26, 1979.

DEPARTMENT OF THE INTERIOR

Geological Survey

30 CFR Part 250

Oil and Gas and Sulphur Operations in the Outer Continental Shelf

AGENCY: U.S. Geological Survey, Department of the Interior.

ACTION: Final rule.

SUMMARY: This rule incorporates the modifications of 30 CFR Part 250 required to conform to the Outer Continental Shelf Lands Act Amendments of 1978, 92 Stat. 629 (herein referred to as the "Act"). A proposed rule was published on March 12, 1979, in the Federal Register (44 FR 13527). This rule describes new procedures and, to the extent required, modifications of existing practices and procedures that govern oil and gas and sulphur operations in the Outer Continental Shelf (OCS). The more important changes are: (1) The establishment of a "Remedies and Penalties" procedure which implements the civil penalty requirements of section 24 of the Act; and (2) the revision of the provisions of section 250.12 to incorporate the new lease suspension and cancellation provisions of sections 5, 11, and 25 of the Act. Part 250, as modified, also contains changes designed to make it more readable as directed by Executive Order 12044 and 43 CFR Part 14.

DATE: This rule shall become effective December 13, 1979.

ADDRESSES: A copy of this final rule may be obtained from the following offices of the Geological Survey:

Chief, Conservation Division, U.S. Geological Survey, National Center-Mail Stop 620, Reston, Virginia 22092.

Conservation Manager-Eastern Region, U.S. Geological Survey, 1725 K Street, N.W., Suite 204, Washington, D.C. 20006.

Conservation Manager-Gulf of Mexico Region, U.S. Geological Survey, 336 Imperial Office Building, P.O. Box 7944, Metairie, Louisiana 70010.

Conservation Manager-Western Region, U.S. Geological Survey, 345 Middlefield Road, Menlo Park, California 94025.

Area Oil and Gas Supervisor-Pacific Area, U.S. Geological Survey, 1340 West Sixth Street, Room 160, Los Angeles, California 90017.

Area Oil and Gas Supervisor - Alaska Area, U.S. Geological Survey, 800 "A" Street, Suite 109, Anchorage, Alaska 99501.

FOR FURTHER INFORMATION CONTACT:

Gerald D. Rhodes, Branch of Marine Oil and Gas Operations, Conservation Division, U.S. Geological Survey, National Center-Mail Stop 620, Reston, Virginia 22092 (703) 860-7531.

SUPPLEMENTARY INFORMATION:

Background. On September 18, 1978, the Act was signed into law. Certain provisions of the Act supersede the existing practices and procedures and necessitate their revision. In addition, on March 23, 1978, the President issued Executive Order 12044 directing executive Agencies to make regulations as simple and clear as possible. By Federal Register notice of March 12, 1979 (44 FR 13527), the Department of the Interior published proposed revisions to 30 CFR Part 250, Oil and Gas and Sulphur Operations in the OCS. The notice explained that most of the proposed changes were designed to eliminate unnecessary and redundant provisions, to reorganize Part 250 into a more coherent program, and to assure that the provisions of the regulations are written in clear English.

Comments. A total of 22 sets of comments and recommendations were timely submitted in response to the invitation contained in the notice of proposed rule published March 12, 1979. The comments and recommendations varied widely in their nature, scope, and content. They presented the views of 2 environmental organizations, 5 State and Federal Government Agencies, and 15 oil and gas companies and trade organizations.

Public Hearings. Oral testimony relating to the proposed revision of 30 CFR Part 250 was also taken at a public hearing held in Washington, D.C., on May 8, 1979.

Differences Between Proposed Rule and Final Rule. The differences between the provisions of the final rule published today and the proposed rule are the result of the Department's efforts to incorporate the comments of the public, to make the provisions of the final rule clearer, and to insure conformance with the Act.

DISCUSSION OF MAJOR COMMENTS

GENERAL COMMENTS

Dual regulation. Several respondents commented that a clearer identification of the administrative responsibilities of the Geological Survey and other Agencies, both within and outside the Department of the Interior, is needed. The regulations issued by this notice apply only to those responsibilities and authorities of the Secretary of the Interior under the Act and other laws applicable to oil and gas and sulphur activities on the OCS, which the Geological Survey administers. The Act and other statutes applicable to the OCS establish responsibilities and authorities for Agencies other than the Department of the Interior. For example, section 22(a) of the Act requires the Secretary of the Interior, the Secretary of the Department in which the Coast Guard is operating, and the Secretary of the Army to enforce safety and environmental regulations pursuant to the Act. These regulations are not intended to duplicate, and are not inconsistent with, the regulations of other Agencies. In fact, section 21(f)(1) of the Act requires that the Secretary of the Interior consult with the heads of other appropriate Departments and Agencies to assure that inconsistent or duplicative requirements are not imposed. We do not believe, however, that these regulations should delineate the OCS-related responsibilities of any Agency except the Geological Survey.

Need for regulatory analysis. Several respondents indicated that implementation of the regulations, as proposed, represents a significant regulatory action and, pursuant to Executive Order 12044, requires preparation of a regulatory analysis. Prior to the publication of the proposed modifications of 30 CFR Part 250, the Geological Survey prepared a Negative Declaration and Regulatory Analysis. The document examined the criteria for determining whether the proposed revisions to the regulations constituted a significant regulatory action. The review resulted in a determination that the proposed revision of 30 CFR Part 250 to implement the Act did not constitute a significant regulatory action.

A review of that determination, in light of the comments of respondents, failed to show any basis for changing this determination. We therefore reject the contention that a regulatory analysis is called for by the criteria set out in Executive Order 12044.

Identity of official to administer regulations. Several respondents expressed concern over the designation of the Director of the Geological Survey as the responsible official for administering the regulations in 30 CFR Part 250. Current regulations identify the Supervisor as the responsible official. Respondents indicated that the proposed change would tend to create delays and confusion, and would disrupt the present system which has worked well for many years. We have not adopted the suggestion to designate the Supervisor as the Geological Survey official administering these regulations. However, the change incorporated into these regulations will not appreciably alter present practices and procedures under which the Area Oil and Gas Supervisors and District Supervisors administer the provisions of 30 CFR Part 250. Most of the authorities previously delegated to the supervisor through the regulations will be delegated to the Supervisor or a comparable officer through a Delegation of Authority from the Director. This approach anticipates a pending reorganization of the Conservation Division which will modify the organizational structure of offices at the Region, Area, and District levels.

Effective date of rule. One respondent noted that the notice of proposed rule gave on effective date for the final rule. This notice identifies the effective date of these regulations as December 13, 1979, because this is the date the regulations in section 250.34 of this part will be effective.

SECTION-BY-SECTION DISCUSSION

GENERAL PROVISIONS

Section 250.1 Purpose and authority

Two respondents suggested minor language changes to indicate that the revised regulations will be applicable to leases issued after the effective date for the revised regulations. This recommendation was not adopted. The regulations in this Part are applicable to all operations conducted under a lease issued or maintained under the Act. Therefore, the regulations are applicable to all leases issued under section 8 or validated under section 6 of the Act. The establishment of a December 13, 1979, effective date addresses the need for leadtime to make required procedural changes.

Section 250.2 Definitions

Several respondents recommended that the term "affected State" be defined more precisely. Adoption of the definition of "affected State"

proposed by notice in the Federal Register of June 7, 1978 (43 FR 24710), was recommended by some respondents. We have not adopted this recommendation. Whether a State is an affected State under the criteria established under section 201(f) of the Act depends on the proposed OCS activities and the location and significance of onshore activities relating to those OCS activities. No further action will be taken on the notice published June 7, 1978 (43 FR 24710), which tentatively identified "affected States." For purposes of the regulations in Part 250, the identification of "affected States" will be made on a case-by-case basis by the Director or the Director's designee.

A number of respondents requested the development of a definition for "affected local government" and a revision in the proposed definition of "area adjacent to a State."

The new definition of "affected local government" reflects the congressional intent to provide Governors of affected States with a degree of discretion in the identification of affected local governments. The new definition of "area adjacent to a State" was taken from paragraph 4(a)(2) of the OCS Lands Act.

Several respondents suggested revisions to the proposed definition of "correlative rights". One suggestion was to delay publishing a definition of correlative rights until revisions to the regulations governing unitization, pooling, and drilling agreements are published. These recommendations have been rejected. There appears to be confusion over what is meant by "correlative rights." The term "correlative rights" does not indicate an ownership of the minerals in place. Instead, it applies to the lessee's rights to explore for and to develop and produce oil and gas from the leasehold. As long as these rights are not unfairly restricted, as compared to the rights of lessees on adjacent leaseholds, the lessee's correlative rights have been protected. One means for protecting correlative rights is the limitation of the number of wells that can be drilled in a field, pool, or like area, i.e., wellspacing. The responsibility and authority for placing limitations on the number of wells drilled to a given reservoir are found in § 250.17 and OCS Order No. 11.

A number of respondents recommended that the definition of "drilling operations" be broadened to include such things as waiting for severe weather to subside or moving off location. These recommendations have not been adopted. Instead, the definition of "drilling operations" have been modified to clearly indicate that the physical penetration of the seafloor, in preparation to create a borehole, is required.

One respondent recommended that the proposed definition of "exploration" be expanded to include onshore support and administrative activities necessitated by offshore exploration. This recommendation has not been adopted. The onshore support and administration activities relating to the offshore exploration activities of a lessee were not viewed by Congress as a proper element to be included in the definition of exploration activities. (See section 2(k) of the Act(43 U.S.C.1333).)

One respondent indicated that the definition of "fair market value" is insufficient and that guidelines should be included to indicate how the Secretary will make "fair market value" determinations. We have rejected this recommendation. Although the definition used has been modified to make the language more clear, it is similar to the definition found in section 201 of the Act. Also, the guidelines used by the Director to make value determinations are contained in a different section of the regulations (i.e., § 250.64).

After reviewing the comments on § 250.80 (i.e., "Remedies and Penalties"), we decided to change the title "Hearing Officer" to "Reviewing Officer" because we feel that title more precisely reflects the role these individuals will play in the process outlined in § 250.80. Also, we decided to include a definition of "Reviewing Officer" in § 250.2.

A number of respondents recommended the deletion of the proposed definition of "knowingly and willfully." They argued that this term is well defined in case law and that it is unnecessary for the Department to attempt a refinement of the standard administratively. We agree and have deleted the definition from the final rule.

The definition of "minerals" has been modified to conform to the definition of minerals in 43 CFR 3300.0-5 published in the Federal Register on June 29, 1979 (44 FR 38277).

One respondent suggested that the proposed definition of "production" be shortened by deleting the statement that the definition of production depends on the context in which the term is used. This suggestion has not been adopted. The meaning of the term "production" varies as to the context in which it is used. Thus, it is appropriate for the definition of "production" to state that the specific meaning depends on the context in which the word is used.

One respondent recommended that the proposed definition of "violation" be expanded to cover violations of acts other than the Act and the regulations promulgated under the Act. This recommendation has not been adopted. Section 24 of the Act explicitly states that the Secretary is empowered to enforce "*** any provision of this Act, any regulation or order issued under this Act, or any term of a lease, license, or permit issued pursuant to this Act."

A number of respondents recommended the expansion of the proposed definition of "waste

of oil and gas" to include the "production of oil or gas in excess of transportation facilities" because this language is contained in existing regulations. This recommendation has not been adopted. The language in question was not used in the proposed rule because the current and predicted shortages of domestically produced oil and gas make it unnecessary. We continue to believe that the language is not needed.

One respondent recommended changes in the proposed definition of "well reworking operations." The definition has been refined to indicate more clearly that work needed to increase the capability of a service well to perform a needed service, and work which is related to cleanout operations to increase or restore production also constitute well reworking operations.

Section 250.3 Data and information to be made available to the public.

This section appeared as § 250.97 in the proposed rule. It has been moved to § 250.3 in the final rule because we believe that the contents of the section more properly fall under the "General Provisions" portion of the regulations in Part 250.

Section 250.4 Privileged and proprietary data and information to be made available to affected States.

The provisions of this section have been added to implement the provisions of section 8(g) of the Act.

Section 250.5 Effect of regulations on provisions of section 6 leases.

This section appeared as § 250.100 in the proposed rule. It has been moved to § 250.5 in the final rule because we believe that the contents of the section more properly fall under the "General Provisions" portion of the regulations in Part 250.

JURISDICTION AND FUNCTIONS OF THE DIRECTOR

Section 250.10 Jurisdiction.

Several recommendations were received with reference to this section. Two respondents suggested that language be added to make it clear that the Director's jurisdiction covers activities conducted pursuant to a lease. We adopted this recommendation because there are activities, such as fishing within the area covered by a leasehold, that are not subject to the jurisdiction of the Director.

Section 250.11 Functions.

Several respondents recommended changes in the proposed provisions describing the functions of the Director. Some suggested the elimination of language which they felt created an imbalance between protection of the environment and orderly energy resource development. Still others recommended broadening the functions by making a specific reference to the need to protect marine sanctuary and fishery resources. We have rejected these recommendations. The functions listed have been derived from the provisions of the Act, and any effort to constrict or expand these functions would be inconsistent with the provisions of the Act. Section 250.11(a)(5) has been expanded to indicate that the Director's consultation process may also include executives of affected local governments and other interested parties. We view the phrase "other interested parties" as including lessees and permittees whose interests may be affected by an action of the Director.

Section 250.12 Suspension of operations and lease cancellation.

Several respondents submitted comments and recommendations for the reorganization of this section and its modification to make the provisions more logical and readable. To the maximum extent practicable, these comments and recommendations have been adopted.

While these modifications incorporate many changes suggested by respondents, some were rejected. For example, the suggestions that the lease term be suspended while exploration plans are processed under § 250.34-1 or while development and production plans are being processed pursuant to § 250.34-2 have not been adopted. It is the Department's view that it is the lessee's responsibility to assure that comprehensive exploration plans are submitted and carried out early enough in the initial term of a lease to allow for the discovery and delineation of hydrocarbon accumulations, and to prepare and submit a schedule for the expeditious initiation of production. Similarly, we rejected the recommendation that a suspension not become effective until 30 days following the lessee's receipt of notice of the suspension. Suspensions, particularly suspensions for protection of the environment, are designed to meet special situations which may demand immediate action.

Several respondents commented upon the proposed provisions of § 250.12(d)(2)(i)(now § 250.12(d)(1)), which spelled out the Director's authority to require a lessee to conduct site-specific studies to identify and evaluate the cause(s) of the hazard(s) generating a suspension, the potential damage from the hazard(s), and the mitigating measures for the

hazard(s). Some supported this provision, but many opposed it for varying reasons. As a result of these comments, the text of § 250.12 (d)(1) has been modified to indicate that cost of the studies will be borne by the lessee unless the Director arranges for the cost to be borne by a party other than the lessee. We did not adopt the recommendation that the Director's report, which is to be made to the Secretary on the basis of the study conducted under § 250.12(d)(1), be made available for public comment prior to being finalized and forwarded to the Secretary. This approach, however, does not preclude the Director from inviting public comment on the report.

Several respondents questioned the provision of § 250.12(d)(2)(iv) of the proposed rule which limited suspensions to 5 years. This provision has been dropped from the final rule, and language from section 5(a)(2)(A) and (B) of the Act has been incorporated as § 250.12(e).

One respondent recommended that the hearing procedures to be followed before a lease is cancelled be described in detail in these regulations. This suggestion has not been adopted because hearing procedures are clearly spelled out in other regulations of the Department (see: 43 CFR Part 4). Since any effort to cancel a lease would be taken by an authorized representative of the Secretary, the action would be subject to appeal pursuant to Department regulations. Then, depending on the facts of the case, the lease may be cancelled administratively subject to judicial review in a U.S. District Court, or cancelled through the initiation of cancellation proceedings in the U.S. District Court.

Several respondents recommended that the provisions of § 250.12 recognize, where appropriate, the ability to cancel a lease pursuant to subsection (5)(a)(2) of the Act. This suggestion has been adopted and has had a significant bearing on the overall organization of the section.

Several respondents recommended that provisions relating to the cancellation of leases for failure to submit a development and production plan provide an exemption for leases in the western Gulf of Mexico. We believe the Act allows the Department to continue to require the submission of development and production plans for leases in the western Gulf of Mexico and that such an exemption would, therefore, be inappropriate.

Section 250.13 Temporary approvals.

Two respondents suggested that temporary approvals are really advance approvals and that the title of the section should be changed accordingly. We did not adopt this recommendation. The approvals granted under this section are temporary because they are contingent upon subsequent official confirmation. We also rejected the recommendation that temporary approvals be granted only after public review, because the whole purpose of this section is to give the Geological Survey the administrative flexibility it needs to promptly and efficiently deal with a wide variety of day-to-day circumstances.

Section 250.15 Drilling and abandonment of wells.

A number of respondents suggested dropping the phrase "no longer used" from § 250.14(a). They pointed out that wells that are not being used may still be useful and should, therefore, not be abandoned. We have adopted the recommended change. Also, the language of § 250.15 (a) has been modified to make it clear that the Director must determine that an unused well is no longer useful before requiring a lessee to abandon it. The language has also been modified to make it clear that drilling and other operations pursuant to a lease must be conducted in accordance with a plan approved or prescribed by the Director in accordance with the regulations in 30 CFR Part 250.

Section 250.16 Well potentials and permissible flow.

and

Section 250.17 Well spacing.

The recommendation that environmental considerations be incorporated in these provisions has not been adopted. The regulations in these sections are directed to the proper development and productions of oil and gas accumulations by wells on the OCS. Environmental considerations that are applicable to these wells are addressed in other sections of the regulations in this Part.

Section 250.18 Right of use and easement.

One respondent pointed out that §§ 250.18 and 250.19 (Platforms and Pipelines) ignore the environmental protection requirements of section 5(e) of the Act. As the respondent points out, section 5(e) of the Act relates to "rights-of-way" through the OCS. What the respondent apparently did not recognize is that the provisions of §§ 250.18 and 250.19 relate to grants of "rights of use and easements" and not grants of "rights-of-way". Rights of use and easements for pipelines are addressed in section 5(f) of the Act and not section 5(e). However, platforms and pipelines clearly involve the application of technologies which, if they failed, would have a significant effect on safety, health, or the environment. For this reason, they are subject to the provisions of section 21(b) of the Act.

We have, therefore, added language to make it clear that the best available and safest technologies, as defined by section 21(b) of the Act, must be used.

Several respondents suggested modification of § 250.18(c) to include, as one of the uses for which pipelines can be constructed on the OCS, the delivery of production to a point of transfer. This recommendation has not been adopted. Instead, we have incorporated the specific language of section 5(f)(2) of the Act to describe the pipelines under the Geological Survey's jurisdiction. The recommendation that the Director's authority be expanded to include grants of rights of use and easement to State lessees has not been adopted. Rights of use and easements can only be granted to Federal lessees. State lessees wishing to obtain a right-of-way across the OCS must apply for a grant from the Bureau of Land Management. Finally, the recommendation that § 250.18(b)(3) be modified to permit a lessee a period of 30 days to comment on an application submitted by another lessee has not been adopted. However, as now written, the lessee of any land affected by a grant of a right of use and easement must be notified and given an opportunity to comment on the application for a right of use and easement.

Section 250.19 Access to platforms.

The recommendation that this section be modified to recognize that the best available and safest technologies must be applied to platforms and pipelines has been adopted through the modifications made in § 250.18. Section 250.19 has been revised and renamed to limit the scope of its provisions to the Department's access to platforms.

Section 250.21 Reduction of royalty or net profit share.

Several respondents recommended that one criterion for granting a royalty reduction should be continued production. This recommendation has not been adopted. However, if a well is in danger of being abandoned because of an uneconomic rate of production, the lessee should be able to demonstrate that the continuance of that well in production would actually represent an increase in production when compared with the volume of production that would come from the lease if the well were abandoned. Thus, a reduction in royalty could be granted to "increase production" if the Director determines that such a reduction is justified.

One respondent recommended that a lessee should not be required to show full information regarding carved out interests. This recommendation has not been adopted. We believe that requests for reductions in royalty or net profit share should be justified by a full disclosure of all information relevant to the request.

REQUIREMENTS FOR LESSEES

Subsection 250.30 Lease terms, regulations, waste, damage, and safety.

One respondent suggested that making oral orders effective when issued deprived lessees of an opportunity to comment on the order. The circumstances under which oral orders are issued are usually such that there is no time for notice or comment. We have, therefore, decided to maintain the language contained in the proposed rule.

Three respondents recommended that the threat of harm or damage referred to in subsection 250.30(b) should be qualified by incorporating language which appears in section 5(a)(1)(B) of the Act (i.e., that there must be a serious, irreparable, or immediate threat). We have not adopted the qualifying language. Section 5(a)(1)(B) relates to circumstances under which a lease must be suspended, whereas this provision deals with the degree of protection lessees are required to provide on a day-to-day basis. We believe that a lessee's daily activities on a leasehold must provide a level of protection that is well above the level of protection which would result in a lease suspension under section 5(a)(1)(B).

Section 250.33 Drilling and production obligations.

Several respondents argued that the Secretary does not have the authority to require the lessee to drill a well. We disagree with this argument. Section 5 of the Outer Continental Shelf Lands Act of 1953 provides the Secretary with the authority and this has been strengthened by the language in the Act. Implicit in this mandate is the authority to require the submission of plans because wells must be drilled in accordance with an approved plan.

Section 250.34 Exploration development and production plans.

Regulations in this section were published as a final rule on September 14, 1979, in the Federal Register. They will be effective December 13, 1979.

Section 250.35 Effect of drilling or well reworking on lease term.

Several respondents expressed concern that the proposed language of § 250.35 failed to recognize a situation where a lease was beyond its primary term when production ceases. Language has been added to subsection 250.35(a) to make it clear that, when a lease is beyond

its primary term and producion ceases, the lease will not expire if drilling or well reworking operations are started within 90 days after production ceases.

Section 250.37 Marking platforms, structures, and wells.

The recommendation that the lessee's name not be required on each well on a platform has been adopted.

Section 250.38 Well records.

The recommendation that the regulation state that the Director show cause for requiring reports or records that are not customarily required from all lessees has not been adopted. Although there are specific records and reports which the Director requires of all lessees, there are reports and records that are only required under specific or unusual circumstances. If a lessee believes that the Director should be denied access to records or reports not customarily required from all lessees, the lessee can appeal for relief pursuant to 30 CFR Part 290.

Section 250.39 Tests, surveys, and samples.

A number of respondents recommended that the tests, surveys, and samples referred to in this section should be performed "when required by the Director." This language appears in existing regulations, but was dropped in the proposed rule. The lessee is responsible for designing and carrying out adequate sampling, testing, and surveying programs which are essential for safe and efficient operations. Given the mandates of the Act, we believe that the mandatory language is appropriate and reasonable and have, therefore, rejected this recommendation. This is also the rationale for rejecting the recommendation that the lessee be given some sort of veto power over whether or not the samples, tests, and surveys are performed. When, in the Director's opinion, the sampling, testing, and surveying programs of the lessee are inadequate, the Director has the authority to require the lessee to initiate and conduct the sampling, testing, and surveying activities necessary to assure the adequacy of the programs.

Section 250.40 Directional survey.

One respondent recommended that the regulations specify an interval between test points in drilling wells. This recommendation was not adopted because an interval is already specified in the OCS Order No. 2.

Section 250.42 Treatment of production.

Two respondents recommended that this section be modified to recognize that certain bidding systems provided for in section 205 of the Act do not call for the payment of royalty. We have not adopted this recommendation because all of the bidding systems currently in use require the payment of royalty, and we believe it is understood that if and when a system is used which does not require the payment of royalty, then no royalty would be due under § 250.42.

Section 250.43 Pollution and waste disposal.

One respondent recommended that § 250.43(b) be modified to limit the lessee's responsibility for control and cleanup of pollution to something less than "total" because the respondent believed the provision is unreasonable. This recommendation has not been adopted. The provision as written, conforms to the provisions of section 304 of Title III of the Act. Also, two respondents recommended deleting language that indicates that the cleanup shall be at the expense of the lessee because others might legitimately be responsible for some of the costs. Once again, this recommendation was rejected because it is inconsistent with the provision of section 304 of Title III of the Act.

Section 250.44 Borehole abandonment.

Two respondents recommended that a specific requirement be added to the regulations that the wellheads of abandoned wells be removed to a sufficient depth to prevent obstructions to commercial fishing in the area. This recommendation has not been adopted because the specific details for well abandonment are contained in OCS Order No. 3, which prohibits leaving obstructions which may interfere with commercial fishing operations.

Section 250.45 Accidents, fires and malfunctions.

Several respondents recommended that the scope of the Director's jurisdiction, as compared to that of other agencies having parallel jurisdictions (e.g., the Coast Guard), be clarified. Language has been adopted to indicate that the accidents, fires, and malfunctions referred to in this section relate to activities associated with operations pursuant to a lease.

Section 250.47 Sales contracts.

This section has been clarified to indicate that the term "all contracts" includes all contract modifications such as amendments and

terminations.

Section 250.49 Royalty, net profit share, and rental payments.

This section has had clarifying language added to indicate that the payments of rentals, royalties, and net profit shares may be made by "electronic transfer of funds." The section has also been clarified to show that interest is due and payable on the late payments of rentals, royalties, or net profit shares. The amount of interest specified is that specified in section 304(g)(2) of Title III of the Act.

Section 250.54 Marking of equipment.

Several respondents requested the addition of clarifying language to require the marking of equipment that is "of such a nature" as to interfere with commercial fishing. This suggestion has been adopted. Language has also been added to indicate that the manner in which materials, tools, containers, etc., are marked must be approved or prescribed by the Director.

Section 250.56 Fishermen's Contingency Fund.

One respondent recommended that "geophysical permits" be exempt from the payment of money into the Fishermen's Contingency Fund. This recommendation has been rejected because section 402(c) of Title IV of the Act makes specific reference to the holders of permits in identifying those who must contribute to the Fishermen's Contingency Fund.

MEASUREMENT OF PRODUCTION AND COMPUTATION OF ROYALTIES

Section 250.61 Measurement of gas.

One respondent recommended the use of a standard pressure base of 14.73 pounds per square inch absolute, 60° Fahrenheit, and corrected for deviation from Boyle's Law. This recommendation has not been adopted. The system of contracts and conversion practices presently being used by operators would be unnecessarily disrupted by a change of this base. However, it should also be noted that the language of the provision allows adequate flexibility for the use of other standards.

Section 250.63 Quantity basis for substances extracted from gas.

Two respondents recommended that the definition of net output of a plant be limited to substances produced "for sale." We have rejected this suggestion. We regard the net output of a plant to include all of the substances produced by the plant without regard to the ultimate disposition of those substances.

Section 250.64 Value basis for computing royalties.

The suggestion that the "Director" rather than the "Secretary" establish the reasonable unit value has been rejected. The reasonable unit value, when established by the Secretary, serves as a floor value. The value that the Director uses to compute royalties due the United States under § 250.64 may not be less than "reasonable unit value" established by the Secretary, if the Secretary establishes such a value.

Section 250.65 Royalty on oil.

Several respondents objected to including oil used as fuel in the computation of royalty. Since this question currently is the subject of litigation [Amoco Production Co. v Andrus No. 77-3351-C(E.D.La.)], they recommended that the language in the existing regulations not be changed pending a decision by the court. Since regulations implement administration policy as well as statutory mandates, we believe it is appropriate for the language of the final rule to be consistent with the Department's policy on this matter, and have, therefore, rejected this recommendation.

Section 250.66 Royalty on unprocessed gas.

This section has been modified to make it clear that the value of wet gas and entrained liquids may be established by using a Btu or some other appropriate adjustment factor to adjust the value of the gas without the entrained liquids. This provision is consistent with the Department's current policy on this matter.

REMEDIES AND PENALTIES

Section 250.80 Remedies and penalties.

Several respondents submitted extensive comments and recommendations regarding the provisions of § 250.80.

Before discussing the changes made in this section, two points must be made about the overall approach envisioned in the requirements contained in this section. First, the provisions conform to the recommendations adopted by the Administrative Conference of the United States on June 8, 1979. (See Recommendation 79-3: "Agency Assessment and Mitigation of Civil Money Penalties.") Second, as pointed out in the preamble of the proposed rule, practices and procedures being adopted parallel those under which the U.S. Coast Guard carries out its responsibilities for assessing and collecting civil penalties.

Several respondents argued that the person

responsible for the initial handling of a case following the issuance of a citation for an alleged violation should be an impartial party. Some suggested the use of Administrative Law Judges instead of Geological Survey designated Reviewing Officers (formerly Hearing Officers). We agree that the Reviewing Officer must be an impartial party and have incorporated language indicating that the Reviewing Officer is to have no part in the prosecution as well as the investigation of the alleged violation. We do not agree, however, with the implication that a Geological Survey employee is incapable of conducting an impartial inquiry. Section 24 of the Act does not alter existing enforcement procedures. Instead, it expands them to include the assessment of civil penalties. Since existing enforcement procedures are conducted by Geological Survey personnel, we feel it is appropriate that the initial handling of cases following the issuance of a citation for an alleged violation be conducted by a Geological Survey employee. It should be noted that any appeal from a decision of the Director, U.S. Geological Survey, will be handled by Administrative Judges of the Board of Land Appeals.

Numerous respondents recommended that alleged violators be provided with an early notice of the alleged violation. We agree and have included language in § 250.70, "Reports and Investigations of Apparent Violations," indicating that alleged violators will be notified of the matters under investigation.

Several respondents suggested that the alleged violator should be given a copy of the report on the alleged violation that is transmitted from the Director's designee to the Reviewing Officer. We have rejected this suggestion. In order to protect against frivolous claims (a concern expressed by one of the respondents), we have incorporated a number of reviews of the evidence before further action is taken on any alleged violation. One of these reviews is conducted by the Reviewing Officer when the report is first forwarded by the Director's designee. If the Reviewing Officer's preliminary examination confirms that an alleged violation may have occurred, then the Reviewing Officer will notify the party of the allegation and its right to examine the material in the case file.

Some respondents questioned whether the transmission of the alleged violator's prior record would prejudice the Reviewing Officer's evaluation of the evidence that the alleged violation occurred, and one respondent recommended that the alleged violator's prior record should only be used in the consideration of the size of the penalty to assess. We understand the concern expressed and have decided to modify the final rule to indicate that the party's prior record will not be forwarded until the determination that a violation has occurred, and that the prior record shall be used to determine the amount of the penalty to assess.

One respondent recommended that the Geological Survey should limit its investigations to alleged violations of rules under its jurisdiction. This respondent appears to be confused over the provisions of the proposed rule. Under both the proposed and final rule, authorized representatives of the Survey, the Coast Guard, and the Corps of Engineers will continue to enforce their own rules and issue citations in accordance with their own regulations. Those citations which call for the consideration of imposing a civil or criminal penalty under the Act will be forwarded to the Director's designee for further action. This approach is consistent with the requirements of the provisions of section 24 of the Act, and it insures the efficient handling of enforcement actions.

A number of respondents objected to the provisions which protect the identity of confidential informants. They argued that the accused should be afforded the opportunity to confront the accuser. We have decided to maintain this provision, but have modified it to indicate that the protection of confidential informants is limited to the civil proceedings outlined in § 250.80-1. This provision is designed to protect an employee of the party under investigation from retailiation for reporting an alleged violation.

One respondent recommended that the public be notified of the proceedings under § 250.80-1 and that interested parties be allowed to intervene in the proceedings. We have rejected these recommendations. The proceeding contemplated under § 250.80-1 is an extension of the Geological Survey's existing enforcement functions, and is designed to insure that cases are handled in an expeditious fashion with due regard for the protection of the party's legal rights. However, any person or group that is involved in the report of the alleged violation will be notified of the initiation of proceedings.

Some respondents suggested that the Geological Survey require that a verbatim transcript be kept of all hearings. In the interest of efficiency and economy, we do not believe that such a requirement is necessary. However, a party in the proceeding can arrange for a verbatim transcript, at the party's expense, to be made of the proceeding.

SPECIFIC CHANGES IN SECTION 250.80

The changes made in § 250.80 are primarily organizational in nature and have been made to clarify the provisions. We have moved the content of § 250.80(a) and divided it into two new §§ 250.70 and 250.71. These new sections are entitled "Investigations" and "Report on investigations." Subsections 250.80(r) and (s)

have been combined as § 250.80-2.

Subsection 250.80(q) has been moved and made into a new § 250.72, "Knowing and Willful Violations." This provision follows the language of subsection 24(a) of the Act. The language of the final rule also makes it clear that in those instances where a knowing and willful violation may have occurred, the case will be referred immediately to the Department of Justice.

Other refinements have been made in the text of § 250.80 to make it clear that determinations under the provisions of the section will be subject to the appeals process described in 30 CFR Part 290.

One respondent objected to the interest provision found in § 250.80(p). In response to that objection, § 250.80(p) has been modified by deleting the flat 12% interest charge and by substituting a requirement to pay the average highest commercial interest rate for the period during which interest is due. This new language follows the language of the Act [see: paragraph 304(g)(2)]

AUTHORS: Thomas McCloskey, Office of the Assistant Secretary--Energy and Minerals, U.S. Department of the Interior (202/343-4457); Douglas Fant, Office of the Solicitor, U.S. Department of the Interior (202/343-4325); and Gerald D. Rhodes, Geological Survey, U.S. Department of the Interior (703/860-7531).

Environmental Impact and Regulatory Analysis. The Department of the Interior has determined that the revision of the regulations in 30 CFR Part 250, in accordance with this notice, is not a major Federal action significantly affecting the quality of the human environment and will not require preparation of an Environmental Impact Statement. The Department has also determined that this notice of final rule is not a significant rule and does not require preparation of a regulatory analysis under Executive Order 12044 and implementing regulations 43 CFR Part 2.

JOAN M. DAVENPORT,
Assistant Secretary of the Interior

OCTOBER 23, 1979

2. Preamble, 30 CFR 250.34, Exploration, Development, and Production Activities, 44 FR 53686, September 14, 1979.

DEPARTMENT OF THE INTERIOR

Geological Survey

30 CFR Part 250

Oil and Gas and Sulphur Operations in the Outer Continental Shelf

AGENCY: Department of the Interior, U.S. Geological Survey.

ACTION: Final Rule

SUMMARY: This rule incorporates the modifications of 30 CFR 250.34 required to conform to the Outer Continental Shelf (OCS) Lands Act Amendments of 1978, 92 stat. 629 (herein referred to as the "Act"). A proposed rule was published on January 17, 1979, in the Federal Register (44 FR 3513). The proposed rule described modifications in existing practices and procedures related to (1) exploration activities on OCS oil and gas leases, (2) coordination and consultation with the Governors of affected States and the executives of affected local governments, and (3) development and production activities on OCS oil and gas leases. Issuance of this rule implements the changes that are needed to make the provisions of section 250.34 consistent with the Act.

DATES: This rule becomes effective December 13, 1979.

ADDRESSES: A copy of 30 CFR 250.34 may be obtained from the following offices of the Geological Survey:

Director, U. S. Geological Survey; National Center--Mail Stop 620, Reston, Virginia 22092.

Consevation Manager--Eastern Region, U.S. Geological Survey, 1725 K Street, N.W., Suite 204, Washington, D.C. 20244.

Conservation Manager--Gulf of Mexico Region, U.S. Geological Survey, 336 Imperial Office Building, P.O. Box 7944, Metairie, Louisiana 70010.

Conservation Manager--Western Region, U.S. Geological Survey, 345 Middlefield Road, Menlo Park, California 94205.

Area Oil and Gas Supervisor--Pacific Area, U.S. Geological Survey, 1340 West Sixth Street, Room 160, Los Angeles, California 90017.

Area Oil and Gas Supervisor--Alaska Area, U.S. Geological Survey, 800 "A" Street, Suite 109, Anchorage, Alaska 99501.

FOR FURTHER INFORMATION CONTACT:

Gerald D. Rhodes, Branch of Marine Oil and Gas Operations, Conservation Division, Mail Stop 620, U.S. Geological Survey, National Center, Reston, Virginia 22092, (703) 860-7531.

SUPPLEMENTARY INFORMATION

Background: Rules establishing practices and procedures under which the U.S. Geological Survey (herein referred to as the "Survey") makes information contained in exploration plans and development and production plans available to affected States, executives of affected local governments, and other interested parties were published January 27, 1978 (43 FR 3880). Those practices and procedures were set out in a revised § 250.34 of Title 30 of the Code of Federal Regulations. On September 18, 1978, the OCS Lands Act Amendments of 1978 were enacted (Public Law 95-372). Certain provisions of the Act required revision of the regulations published January 27, 1978. By notice of November 1, 1978 (43 FR 50903), the Department of the Interior temporarily suspended certain provisions of 30 CFR 250.34 pending full implementation of the Act. A proposed rule incorporating the modifications of § 250.34 was published January 17, 1979 (44 FR 3513). In addition, on May 10, 1979, proposed modifications to 30 CFR 250.34 were published to implement the requirement of section 5(a)(8) of the Act that the Secretary of the Interior issue regulations which provide for compliance with the national ambient air quality standards pursuant to the Clean Air Act (42 U.S.C. 7401, et seq.) to the extent that activities authorized under the Act significantly affect the air quality of any State. Those modifications are being developed under a separate rulemaking activity.

Comments: A total of 50 sets of comments and recommendations were timely submitted in response to the invitation contained in the notice of proposed rule published January 17, 1979. Comments and recommendations were received from 2 private citizens, 5 public interest groups, 12 State and local government agencies, and 31 oil and gas companies and trade organizations.

Public Hearings: Oral testimony relating to the proposed revisions of 30 CFR 250.34 was also taken at public hearings held in Los Angeles, California; New Orleans, Louisiana; and Washington, D.C.

Differences Between Proposed Rule and Final Rule: The differences between the provisions

of the final rule and the provisions of the proposed rule are the result of the Department's efforts to incorporate the comments of the public, to make the provisions of the final rule more clear, and to assure conformance with the Act. In this regard, special attention has been given to the specific provisions of sections 5, 11, 19, 21, and 25 of the Act (43 U.S.C. 1334; 1340; 1345; 1333; and 1351 respectively).

DISCUSSION OF MAJOR COMMENTS

General Comments: (1) Duplication of efforts. Several respondents suggested implementation of the proposed regulations would result in unnecessary duplication of effort by lessees. In keeping with Departmental policy, every effort was made to eliminate duplicative paperwork, reduce the volume of material submitted, and simplify the review procedures as fully as possible. Our review of the proposed rule identified no instance of significant duplication. When a lessee is required to submit information or data already in the possession of the Survey office that is to review the plan and accompanying Environmental Report, the lessee shall incorporate that information or data into the plan or report by appropriate reference identifying the documents and page numbers where the specific information or data will be found in the records of the Survey.

(2) Need for regulatory analysis. Several respondents suggested that implementation of the proposed regulations would have a significant impact on the Nation's economy and the oil and gas industry. They recommended the preparation of a regulatory analysis pursuant to Executive Order 12044. Prior to the publication of the modifications of 30 CFR 250.34 the Survey prepared a Negative Declaration and Regulatory Analysis. The "negative declaration" was based upon examination of the criteria established by the Department of the Interior (43 CFR Part 14) to determine whether the proposed regulations constituted a significant regulatory action requiring preparation of a regulatory analysis under Executive Order 12044. The examination indicated that an analysis was unnecessary based upon the following considerations: (1) The proposed changes were being made to existing regulations and did not mark a fundamental departure from established practices and procedures; (2) the proposed changes were in response to specific statutory requirements; and (3) the proposed changes should decrease the financial burden borne by lessees operating in the western Gulf of Mexico by eliminating the requirement that Environmental Reports be submitted with exploration plans or development and production plans, unless information contained in an Environmental Report is needed by a State to make a coastal zone consistency determination.

A review of that determination and the comments submitted by respondents failed to develop any basis or criteria which demonstrated any error in the previous negative determination or to justify a change in that determination.

(3) Need for Environmental Impact Statement. Several respondents indicated that implementation of the revised regulations would constitute a major Federal action significantly affecting the quality of the human environment, and that preparation of a detailed environmental impact statement (EIS) is required for compliance with section 102(2)(C) of the National Environmental Policy Act. Prior to the publication of the proposed modifications of 30 CFR 250.34, the Survey prepared a Negative Declaration and Environmental Assessment. The "negative declaration" was based upon the fact that the proposed regulations are specifically designed to, among other things, assure the protection of the marine, coastal, and human environments. The proposed regulations recognize that exploration activities and development and production activities may significantly affect the environment and provide for the evaluation of the effects of those activities. In those instances where significant impacts adversely affecting the marine, coastal, and human environments are identified, EIS's will be prepared in accordance with section 102(2)(C) of the National Environmental Policy Act.

(4) Identity of official to administer regulations. Several respondents expressed concern over the designation of the Director of the Geological Survey as the responsible administering official in 30 CFR 250.34. Current regulations identify the Supervisor as the official responsible for administering the regulations in 30 CFR 250.34. Respondents indicated that the proposed change would tend to create delays and confusion, and would disrupt the present system which has worked well for many years. We have not adopted the suggestion to designate the Supervisor as the USGS official administering these regulations. However, the change incorporated into these regulations will not appreciably alter present practices and procedures under which the Area Oil and Gas Supervisors and District Supervisors administer the provisions of 30 CFR Part 250, including § 250.34. Most of the authorities previously delegated to the Supervisor through the regulations will be delegated to the Supervisor or comparable officer through a Delegation of Authority from the Director. This approach anticipates a pending reorganization of the Conservation Division which will modify the organizational structure of offices at the Area and District levels.

(5) Effective date of rule. One respondent

recommended that it be made clear that exploration plans and development and production plans submitted after the effective date of these regulations will be subject to the requirements of these regulations. This respondent also questioned when the revised regulations will become effective. The review and processing of exploration plans and development and production plans submitted after the effective date of these regulations will be governed by the applicable provisions of these regulations. The effective date of these regulations will be the 91st day following their publication in the Federal Register as final rule.

(6) Environmental reports. Several respondents took exception to the decision to continue requiring the submission of Environmental Reports in support of exploration plans and development and production plans. Some questioned the Department's legal authority to require the reports, and many complained that the information contained in a lease sale EIS is sufficient to determine the environmental impact of activities covered in plans. Finally, some pointed out that the information required is so detailed, particularly for development and production plans, that the preparation of Environmental Reports is tantamount to preparing an EIS. The Department believes that it has ample authority to require the submission of Environmental Reports and that this authority predates enactment of the OCS Lands Act Amendments of 1978. The specific requirement that a lessee submit an Environmental Report in support of proposed exploration plans and development and production plans has been a part of the regulations governing oil and gas operations in the OCS since January 27,1978. Similar information has been required of lessees on a case-by-case basis since the earliest oil and gas operations were regulated on the OCS. The information contained in Environmental Reports is needed to carry out the purposes of the Act and the specific requirements of sections 11(c)(1), 25(a)(2), and 25(h)(1) of the Act. Although impacts of exploration activities may be covered, to a degree, in the corresponding lease sale EIS, the information and data contained in the corresponding lease sale EIS are not generally sufficiently site-specific to provide adequate environmental information and data for the review of exploration or development and production plans. To the extent that the information and data in the corresponding lease sale EIS are sufficient, the governing provisions of the regulations make it clear that the lessee is to incorporate that information and data in the Environmental Report by appropriate reference and to avoid unnecessary detail and length. The intention is that information be sufficiently detailed to permit the evaluation of the impacts of the proposed activities, considering operating conditions in the lease area as well as past experience. It also recognizes the Department's agreement with the Office of Coastal Zone Management to require specific information in order that coastal States with approved coastal zone management programs will have access to sufficient information for the coastal zone consistency Reviews required under the Coastal Zone Management Act.

(7) Gulf of Mexico exemption. Treatment in the proposed regulations of the exemption for certain Gulf of Mexico leases created in section 25(a)(1) of the Act has raised several questions.

First, some respondents requested clarification of those parts of the Gulf subject to the exemption. A number of commenters accurately pointed out that the proposed regulations are not precise in identifying those parts of the OCS that are adjacent to Florida. One respondent recommended limiting this area to the tracts which are continguous with the seaward boundary of Florida, while most urged the adoption of the area identified in the June 7, 1978, Federal Register (43 FR 24711). In order to correct the ambiguity of the proposed regulatory language, the regulations have been modified to indicate that the Director will determine which OCS areas of the Gulf of Mexico are adjacent to the State of Florida. In making these determinations the Director will use, if they are available, the projected boundaries of each State established by the National Oceanic and Atmospheric Administration.

The terms "eastern Gulf of Mexico" and "western Gulf of Mexico" will be used to differentiate between the portions of the Gulf subject to the exemption. Definitions will be added to 30 CFR 250.2 which indicate that, as used in § 250.34 "western Gulf of Mexico" means all OCS areas of the Gulf of Mexico except those deemed by the Director to be adjacent to the State of Florida and "eastern Gulf of Mexico" means all OCS areas of the Gulf of Mexico deemed by the Director to be adjacent to the State of Florida.

A second issue which arose concerned the extent of the exemption created for western Gulf of Mexico leases. Several respondents argued that leases in the western Gulf of Mexico are exempt, under section 25(a)(1) of the Act, from the requirement that development and production plans must be submitted to and approved by the Director before the commencement of operations. The Department does not agree with this interpretation of section 25 (a)(1) of the Act.

After reviewing the Act, the Conference Committee Report, and the legislative history, the Department is convinced that section 25(a) (1) of the Act does not bar the Secretary from continuing to require the submission of development and production plans for leases in the western Gulf of Mexico. We have interpreted

this section to mean that the procedures for handling of development plans and requirements for plan content, while mandatory for all other areas, do not necessarily apply to development and production activities in the western Gulf of Mexico. The purpose of the Gulf of Mexico exemption is to insure that onerous and unnecessary environmental reporting requirements and burdensome procedures are not imposed on lessees in this area of the Gulf where oil and gas activities have occurred for years.

The information and data contained in development and production plans are as essential for the proper management of development and production activities in the Gulf of Mexico as they are for the proper management of these activities on leases in frontier areas of the OCS. In addition, these plans are necessary for the Secretary of the Interior to carry out a multitude of functions mandated by the Act, including:

(1) Insuring that lessees exploring, developing, and producing OCS leases issued after September 18, 1978, use the best available and safest technologies [see: section 21 (b)];

(2) Preventing waste and insuring the conservation of the natural resources of the OCS [see: section 5(a)];

(3) Insuring the prompt and efficient exploration and development of the OCS [see: section 5(a)(7)];

(4) Enforcing in cooperation with other Federal Agencies, all health, safety, and environmental laws and regulations on the OCS [see: section 5(a)];

(5) Insuring compliance with any rate of production requirements imposed by the Department of Energy [see: section 5(g)];

(6) Exercising the authority to grant suspensions of operations or suspensions of production [see: section 5(a)];

(7) Exercising the authority to authority to authorize or require the unitization of leases [see: section 5(a)(4)]; and

(8) Insuring coordination and consultation with affected States and local governments [see: section 19].

If the information required to carry out these functions is not obtained through development and production plans, then it would have to be obtained through some other means. The Department believes that the most efficient means of obtaining the information is through the plans. The regulations have been modified, however, to allow the Director to limit the amount of information required in development and production plans to that information that is necessary to assure conformance with the Act, other laws, applicable regulations, and lease provisions.

In the proposed rule the Department exempted leases in the western Gulf of Mexico from the requirement that an Environmental Report be submitted with the development and production plan, unless an affected State with an approved coastal zone management program indicates a need for the report to make a coastal zone consistency determination. We have retained this provision. However, we added new paragraphs § § 250.34-3(a)(1)(iii) and 250.34-3(b)(1)(iv) which specifically allow the Director, after consultation with the Office of Coastal Zone Management and the affected State, to limit the information that will be required to be included in Environmental Reports (Exploration and Development/Production) to that information that is necessary for a State to make a coastal zone consistency determination.

Several respondents recommended that the treatment which section 25(a)(1) of the Act provides for development and production plans be extended to exploration plans. Although section 11 of the Act contains no language to support any special treatment for exploration plans in the western Gulf of Mexico, we feel that it makes sense to extend the exemption and limitations that apply to Environmental Reports for development and production plans to Environmental Reports for exploration plans. Exploration, development, and production activities have been conducted for more than 30 years in the Gulf of Mexico, and enough is known about the mature parts of the Gulf area for us to be more selective concerning the environmental information required from lessees. For this reason, we also rejected the suggestion of one respondent that there should be no special exemption from the requirement to submit Environmental Reports with plans in the western Gulf of Mexico.

(8) Identification of affected States. Several respondents wanted the regulations to include a definition of "affected State." The Department has not included a definition of "affected State" in this rule (30 CFR 250.34) because the definition of the terms used in 30 CFR Part 250 are contained in 30 CFR 250.2. The term "affected State" will be defined in 30 CFR 250.2(a).

(9) Early consultation with State and local government agencies. The suggestion that State and local government agencies receive proposed exploration plans and development and production plans before they are "deemed submitted" by the Survey has been rejected. Only complete plans will be available to State and local governments. By submitting one copy of a proposed plan and the accompanying Environmental Report to the Survey for a "completeness" review, the lessee will be protected against the submission and replacement of multiple copies of a deficient plan.

Several respondents asserted that the Department has no authority to take 10 working days for exploration plans and 20 working days for development and production plans for complete-

ness reviews. The Department disagrees with this interpretation of the statute and believes that the incorporation of this procedure will actually speed the review of plans. In order to meet the tight time periods accorded in the Act for the review of plans, it is imperative that only complete plans (i.e., plans containing all of the information required) enter the review process.

The recommendation by one respondent that OCS operators be required to consult with State and local representatives and appropriate Federal officials before making a formal application for approval of an exploration plan or a development and production plan has not been adopted. However, operators are encouraged to participate in preapplication reviews. Informal conferences are believed to be helpful to all concerned.

(10) Formal consultation with affected States during the review of exploration plans. The suggestion that the regulations specify a formal consultation procedure with affected States during review of exploration plans has not been adopted, however, any affected State may submit timely comments. The Department recognizes that the short timeframe mandated for the Federal review of exploration plans (30 days) makes it difficult for States to participate in the review process. Section 11 of the Act is silent on the role of affected States without approved coastal zone management programs in the review of plans; however, we believe that it is consistent with sections 102 and 202 of the Act to afford affected States an opportunity to receive and review plans in a timely fashion. In this regard, a provision has been included that requires exploration plans to be transmitted to affected States within 2 working days of the date the plans are "deemed submitted" by the Director. Recipients are encouraged to review plans and submit their comments on the plans as expeditiously as possible. Comments submitted in a timely fashion will be considered by the Survey.

Several respondents complained that the timeframes for review of plans, especially review of exploration plans, are not adequate to permit State and local agencies to review and comment on proposed plans. The Department cannot alter these timeframes because they are prescribed by the provisions of the Act.

(11) Impact of the preparation of an Environmental Impact Statement on the timeframe allotted for coastal zone consistency review. One respondent recommended that, in instances when the Director determines that approval of a development and production plan is a major Federal action requiring the preparation of an EIS, the 6-month time period for a State's consistency review of a plan should not commence until the final EIS has been published. The Department rejects this recommendation. It is clear from the provisions of section 25 of the Act that a State's coastal zone consistency review is independent of the National Environmental Policy Act review procedures, and the coastal zone consistency review should be completed within the timeframe specified in the Act and the implementing regulations. The Environmental Report is designed to provide all the information needed for the consistency review. To adopt the suggested procedure would result in a delay that is contrary to the intent of Congress.

(12) Consistency concurrence. Several commenters pointed out that the provisions of § 250.34-1(b)(4) and 2(c)(3)(i) of the proposed rules, which requested that the Governor of an affected State with an approved coastal zone management program, notify the lessee and the Director, at the earliest possible time, if the Governor determines that the activities described in detail in a plan will have no significant impacts on land and water uses in the State's coastal zone, are in conflict with provisions of 15 CFR 930.79. We agree and have deleted the provisions.

Also, several commenters pointed out that § 250.34-2(g)(1)(iii) of the proposed rules incorrectly implies that the Director, rather than the States with approved coastal zone management programs, make the consistency determination before approving a development and production plan. We have clarified this situation by dropping, in the final rules, the specific reference to the Coastal Zone Management Act of 1972 in the list of plan approval criteria.

Finally, some commenters asked whether § 250.34-1(h) of the proposed regulations, which states that a lessee "may" revise a plan to accommodate a State's objection(s) raised during the consistency review process and resubmit the plan to the Director and the State for review, conflicts with 15 CFR 930.83, which states that a lessee "shall" revise and resubmit the plan. We agree that there is a conflict in the language contained in the proposed language and have decided to change it to conform to the language of 15 CFR 930.83.

(13) Impact of air quality regulations. One respondent argued that the Secretary may not approve a development and production plan until regulations implementing section 5(a)(8) of the Act are in effect. The Department finds no basis for this assertion. Proposed regulations to implement section 5(a)(8) of the Act were published in the Federal Register on May 10, 1979 (44 FR 27449). It is expected that final rules will be published later this year. The requirements of those final rules will be applicable to exploration, development, and production activities in the OCS. There is no language in the Act to suggest that Congress intended a moratorium or a delay in the exploration for and development of oil and gas

from the OCS until these regulations are promulgated. A primary purpose of the Act is to insure that the extent of oil and natural gas resources of the OCS is assessed at the earliest practicable time.

(14) Consistency of Federal regulations with State regulations. Several respondents pointed out a conflict between the requirements of the proposed § 250.34 regulations and the requirements of regulations of the California Coastal Commission regarding the submission of exploration plans. The § 250.34 regulations provide for the distribution of plans to affected States after they are "deemed submitted." The California Coastal Commission regulations require the advance submission (15 days) of plans for exploration before the Commission begins its coastal zone consistency review process. The Federal regulations governing coastal zone consistency review indicate that the State's coastal zone consistency review process starts with the receipt of a plan from the Secretary of the Interior or the delegate of the Secretary. Personnel of the Department of the Interior have discussed this situation with personnel of the California Coastal Commission. Currently the Commission only requires the advance submission of a general statement of a lessee's exploration intentions so that the Commission may prepare for the receipt of the actual exploration plan and accompanying Environmental Report from the Survey. There is no conflict between this requirement of the Commission's regulations and regulations in this section. Given the expeditious consideration that exploration plans have received by the California Coastal Commission, this procedure seems to be working well.

(15) Public notice of the submission of development and production plans. The recommendation of one respondent that procedures be adopted which require the publication of a notice announcing the submission of development and production plans has been adopted. Upon receipt of a development and production plan, a notice announcing that fact will be published in the Federal Register. Where there is a high degree of public interest in the proposed plan, the Director may also publish a notice in local newspapers.

(16) Mailing list of interested citizens. One respondent suggested that the Director should keep a mailing list of citizens who have expressed interest in receiving copies of plans. Although we have not adopted this suggestion within the body of the regulations. Survey officers that receive and distribute plans are expected to maintain a mailing list of persons interested in knowing when plans have been submitted. In this way, those citizens who wish to be made aware of the information contained in plans can learn of the availability of plans and how the plans can be reviewed.

A related suggestion by one respondent to incorporate language indicating that the Director will consider timely recommendations of the public that are submitted in connection with development and production plans has been adopted.

(17) Area covered by exploration plan and development and production plan. Several respondents suggested modifying language to clarify the area to be covered by an exploration plan. The language of § 250.34-1(a)(1) has been modified to make it clear that an exploration plan may cover more than one leasehold. When an exploration plan covers more than one leasehold, it must represent a comprehensive exploratory program for all of the area included in the leases covered by the plan.

The recommendation of one respondent that lessees be required to cover as many leases as possible when submitting a development and production plan has not been adopted. These regulations allow lessees to include operations on more than one lease in their development and production plans. It should also be noted that other regulations in 30 CFR Part 250 contain provisions which govern the unitization of OCS oil and gas leases. The provisions of those regulations and the provisions of OCS oil and gas leases provide adequate authority to require the submission of development and production plans covering more than one lease.

Several respondents argued that the proposed regulations required too much detail concerning the location of exploratory wells. They recommended using the language of section 11 (c)(3)(C) of the Act, which refers to "the general location of each well," as opposed to the language of the proposed regulations, which refers to "the approximate location" of each well. We have rejected this recommendation because information on well location must be as specific as possible to adequately assess the impacts of the proposed activity, and to assist States with approved coastal zone management programs in the consistency review process.

(18) Deadline for submission of exploration plans. Numerous comments were received regarding the provisions in the proposed regulations which would require lessees to submit exploration plans within a specific timeframe [§ 250.34-1(a)(4)]. Those commenters contended that the provisions should be dropped because they go beyond the authority of the Secretary of the Interior and because the proposed provisions were not sufficiently flexible to reflect the sequential nature of exploration activities on the OCS. The provisions of the proposed regulations in § 250.34-1(a)(4) which would require lessees to submit exploration plans within a specific timeframe were designed to implement section 5(a)(7) of the Act, requiring the Secretary to issue regulations for the prompt and efficient exploration and development of a lease area. After considering the comments the Department decided that a more

flexible approach could be adopted and still meet the mandate of the Act. Therefore, the provisions requiring the submission of an exploration plan within a specific timeframe have been modified to allow the lessee of a lease issued for an initial period of five years to submit, before the end of the second lease year, either an exploration plan or a general statement of exploration intentions. For leases for an initial period of more than five years, the lessee shall submit either an exploration plan or a general statement of exploration intentions within a period of time specified at the time the tracts are offered for leasing. These provisions will only be applicable to leases issued after the effective date of these regulations.

(19) List of required Federal licenses and permits. Some respondents suggested that an exploration plan and a development plan should include a list of all the Federal licenses and permits required to implement the proposed plan. This suggestion has not been adopted. Such a listing is not necessary to complete the documents, data, and information needed before an exploration plan or a development and production plan can be approved. However, the Department supports the Office of Coastal Zone Management in its efforts to encourage lessees to obtain a State's coastal zone consistency review of all interrelated licenses and permits at one time.

(20) Cost of additional surveys. Many respondents questioned the provisions of paragraph 250.34-1(k) and 250.34-2(n) which spell out the Director's authority to require a lessee to conduct geological, geophysical, or other surveys that the Director determines to be necessary for the evaluation of activities to be carried out under a proposed or approved exploration plan or proposed or approved development and production plan. The Department does not believe that it is the intent of Congress that the Department should pay for surveys and reports required to evaluate the exploration, development, and production activities which the lessee proposes to conduct on the leasehold.

(21) Environmental assessment. The Department did not adopt the suggestion that a provision be added requiring the Director to provide the Governor of each affected State with a copy of the environmental assessment prior to the approval of a plan. Environmental reviews are conducted as part of the decision-making process for exploration plans and development and production plans. Environmental assessments generally are not complete until the end of the time allowed for making the decision to approve or disapprove a plan. However, copies of environmental assessments will be provided to those affected States that advise the Survey of their desire to receive them.

(22) Proprietary and confidential information. One respondent suggested that lessees be required to provide a general statement describing the subject matter of confidential and proprietary data and information deleted from exploration plans and from development and production plans. The purpose of this statement would be to give those receiving or reviewing the plans a general idea of the nature of the information covered by the deleted material. This suggestion has been adopted.

(23) General statement of development and production intentions. Varying comments were received on the requirement to submit a general statement of development and production intentions with exploration plans. Some respondents believed that the provision should indicate that such a statement will be required in all cases. Other respondents felt that the provision should be deleted in its entirety. The discretionary authority to require such a statement is provided for in section 11(c)(4) of the Act, and has been retained in the final regulations.

(24) Application for permit to drill. The suggestion of one respondent that these regulations require the Director to transmit a copy of a lessee's application for a permit to drill to affected States for review has not been adopted. The drilling operations covered by these applications are covered by exploration plans or development and production plans which have been reviewed and approved. They are not subject to review under either section 19 of the Act or the Coastal Zone Management Act. However, in order to address the respondent's concern for followup information on activities conducted under approved plans, specific language has been added to the regulations which provides for the transmission to the affected States of copies of each approved application for permit to drill.

(25) Emergency situations. Some respondents asked that the "emergency" conditions under which emergency measures might be approved or directed be more clearly defined. Unfortunately, it is not possible to list all the possible emergency situations which may develop. Any attempt to define "emergency" may limit the Department's ability to authorize or require immediate response to unforeseen situations where quick action is necessary. Therefore, the language of the proposed regulations has been retained.

(26) Conditional approval of exploration plan. Several respondents suggested the elimination of the reference to "conditional" approvals for exploration plans. This suggestion has been adopted. Under the provisions of the regulations published in this notice, an exploration plan may be approved prior to receipt of the State's concurrence with the lessee's coastal zone consistency certificate. However, no license or permit called for under

an approved exploration plan can be granted until the State's concurrence in the lessee's coastal zone consistency certificate is received or is conclusively presumed; or the Secretary of Commerce takes action under the Coastal Zone Management Act.

(27) Review of activities conducted under approved plans. Some commenters recommended deletion of the requirement that activities conducted under approved plans be periodically reviewed by the Director. Others suggested expansion of the provisions to prescribe additional criteria for triggering the review of activities being conducted under approved plans. The Department has rejected these suggestions. Operational experience gained under the current regulations, which contain similar language, indicates that a general statement, like the one included in the proposed regulations, is sufficient to recognize that such reviews are to be expected. The language also provides regulatory authority for those reviews that become necessary for proper implementation of the Act.

SECTION-BY-SECTION DISCUSSION

The discussion in the preceding section was intended to give the reader an overview of the major comments that were received, together with a brief statement of the reasons for accepting or rejecting the suggestions that were offered. In this section, specific changes made in the proposed rules will be described.

§ 250.34-1 Exploration plan.

The first sentence of § 250.34-1(a)(1) has been modified to show clearly that the commencement and continued conduct of exploration activities must be in accordance with the approved exploration plan. The sentence now reads: "No exploration activities, except for preliminary activities, may be commenced or conducted on any leased area except in accordance with an exploration plan approved by the Director."

The third sentence of § 250.34-1(a)(1) has been modified by omitting the phrase "whichever is less" because it added unnecessary confusion to this section of the regulations. Also, the regulations continue to allow the lessee to conduct "preliminary activities." These activities are necessary in order for lessees to gather sufficient information to prepare an initial exploration plan. Without some knowledge of the area's geology, it would be difficult or impossible to prepare a comprehensive exploration plan, including locations for proposed wells for the area. This system conforms with past practice and it has been shown that it does not result in any appreciable adverse environmental impacts.

The fifth sentence of § 250.34-1(a)(1) has been modified to recognize that an exploration plan shall be based upon all available relevant information and may cover more than one leasehold. It is the Department's intention that an exploration plan provide for a comprehensive exploration program for all of the area covered by the lease(s) which the lessee(s) chooses to cover by the plan. The Department expects the lessee to identify all potential hydrocarbon accumulations and the wells that the lessee intends to drill to explore the accumulations. The sentence now reads: "An exploration plan shall be based upon all available relevant information and shall identify, to the maximum extent possible, all potential hydrocarbon accumulations and the wells that the lessee proposes to drill to evaluate the accumulations in the entire area included within the lease(s) covered by the exploration plan."

Section 250.34-1(a)(1)(ii) has been modified to emphasize that exploration plans must include oil spill containment and cleanup plans.

The words "of each directionally drilled well" have been deleted from § 250.34-1(a)(1)(iv). This change reflects our belief that the reviewers of exploration plans are interested in knowing the proposed surface and projected bottom hole locations of all the wells proposed to be drilled under the plan regardless of whether they are "directionally drilled."

The proposed regulations included language in § 250.34-1(a)(2)(i) which indicated that an Environmental Report would be considered part of the exploration plan and would accompany it through all review processes. Because "all review processes" ultimately include plan approval or disapproval, and because the Survey does not approve or disapprove an Environmental Report but instead uses it for the review of the impacts of proposed activities, this section has been modified to make it clear that the plan and Environmental Report are separate documents. An Environmental Report will, however, continue to accompany the related plan through all review processes.

Section 250.34-1(a)(2)(ii) has been modified to indicate that the only time an Environmental Report will be required in the western Gulf of Mexico is when the proposed exploration activities would affect a land or water use in the coastal zone of a State with an approved coastal zone management plan. The Director retains the right, however, to request specific environmental information to make the findings required under applicable law, including but not limited to the Act, and the Coastal Zone Management Act.

Sections 250.34-1(a)(3) and (4) in the proposed rule have been dropped and a new § 250.34-1(a)(3) has been added which states that, for all leases for an initial period of five years issued after the effective date of these regulations, the lessee shall submit before the end of the second lease year either an explora-

tion plan or a general statement of exploration intentions. A new sentence has been added to indicate that for leases with an initial period of more than five years, the lessee shall submit either an exploration plan or a general statement of exploration intentions within a period of time specified at the time the tracts are offered for leasing.

Section 250.34-1(a)(5) has been modified to include the requirement that lessees provide a general statement describing the subject matter of confidential and proprietary data and information that has been deleted from the copies of an exploration plan that are provided for distribution to States and are made available to local government executives, and other interested parties.

Section 250.34-1(a)(6) has been modified to indicate that an exploration plan and its accompanying Environmental Report will not be deemed submitted until the Director has sufficient copies of the documents for the prescribed distribution. Language has also been incorporated that makes it clear that an exploration plan must include the certificate of consistency called for in 15 CFR Part 930 in order for the plan to be considered complete.

Section 250.34-1(b)(1) has been modified to indicate that an exploration plan and its related Environmental Report will be transmitted to the recipients listed in the paragraph "within 2 working days" after the date the plan is "deemed submitted."

Section 250.34-1(b)(3) has been modified by the substitution of a new § 250.34-1(b)(3) which reads: "(3) When it is determined that the activities proposed in an exploration plan will significantly affect any land use or water use in the coastal zone of a State with a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act, the plan will be processed in accordance with the regulations in this section and the regulations governing Federal Coastal Zone Management Consistency Procedures (15 CFR Part 930)."

Section 250.34-1(c) has been modified to refer to the environmental review process outlined in § 250.34-4.

Section 250.34-1(d) has been modified to indicate that the Director will consider all written comments that are timely received from the Governor of an affected State.

Section 250.34-1(e)(2)(ii) has been changed to make it clear that the lessee is responsible for making whatever modifications are necessary to gain approval of an exploration plan.

Section 250.34-1(j)(1) has been modified to indicate that the Director will periodically review activities being conducted under an approved exploration plan. Those activities, coupled with additions to and refinements of existing information and data will serve as the basis for the Director's decision to order a revision of an approved plan.

Section 250.34-1(j)(2) has been modified to indicate that plan revisions which call for additional permits will be subject to coastal zone consistency review. Language has also been added to indicate that the recipients of approved plans will be provided information copies of all revisions of and updates to approved plans.

§ 250.34-2 <u>Development and Production Plans</u>.

The first sentence of § 250.34-2(a)(1) has been modified to read: "(a)(1) No development or production activities may be commenced or conducted on any leased area, except in accordance with a plan of development and production approved by the Director." The changes in this section are designed to make it conform to the language of § 250.34-1(a)(1) and to show clearly that the commencement and continued conduct of development and production activities must be in accordance with an approved development and production plan.

Section 250.34-2(a)(1)(ii) has been modified to emphasize that a development and production plan must include oil spill containment and cleanup plans.

The words "of each directionally drilled well" have been deleted from § 250.34-2(a)(1)(iii). This change reflects our belief that the reviewers of development and production plans are interested in knowing the proposed surface and projected bottom hole locations of all wells proposed to be drilled under the plan regardless of whether they are "directionally drilled."

Section 250.34-2(a)(1)(iv) has been modified by inserting the word "relevant" between "available" and "geological."

Section 250.34-2(a)(2) has been reorganized into subparagraphs (2) and (3). The new § 250.34-2(a)(2) provides that the Director may limit the information that will be required to be included in a development and production plan for leases in the western Gulf of Mexico.

The new § 250.34-2(a)(3)(i) has been modified to make it clear that the Environmental Reports are not considered part of development and production plans. Also, § 250.34-2(a)(3)(ii) has been modified to indicate that the only time that an Environmental Report will be required in the western Gulf of Mexico is when the proposed development and production activities would affect a land or water use in the coastal zone of a State with an approved coastal zone management program. The Director also retains the right to request specific environmental information to make needed findings under applicable law, including the Act, the National Environmental Policy Act, and the Coastal Zone Management Act.

Section 250.34-2(a)(5) has been modified to include the requirement that lessees provide a

general statement describing the subject matter of confidential and proprietary information and data that has been deleted from the copies of a development and production plan that are provided for distribution to States and local government executives and are to be made available to other interested parties.

Section 250.34-2(a)(6) has been modified to indicate that a development and production plan and its accompanying Environmental Report will not be deemed submitted until the Director has sufficient copies of the documents for the prescribed distribution. Language has also been incorporated that makes it clear that a development and production plan must include the certificate of coastal zone consistency called for in 15 CFR Part 930 in order for the plan to be considered complete.

Section 250.34-2(b)(1) has been modified to reflect the changes made in § 250.34-2(a)(6) and to indicate that the Director shall notify the public of the availability of plans and Environmental Reports for review.

Section 250.34-2(c)(3)(i) has been modified to indicate that the Director will consider all comments that are timely received.

Section 250.34-2(d) has been modified to refer to the environmental review process outlined in § 250.34-4.

Section 250.34-2(g)(2)(ii) has been changed to make it clear that the lessee is responsible for making whatever modifications are needed to gain approval for a plan.

The provisions of § 250.34-2(g)(2)(iii)(A) have been revised to recognize that a State's concurrence with a coastal zone consistency certification may be conclusively presumed after 3 months, unless the State indicates that it needs additional time (up to 3 months) to complete its review.

Section 250.34-2(i) has been revised to recognize the authority of the Secretary of Commerce to make a finding under section 307(c)(3)(B)(iii) of the Coastal Zone Management Act.

Section 250.34-2(l) has been modified to indicate that the Director will periodically review activities being conducted under an approved development and production plan. Those activities, coupled with additions to and refinements of existing information and data, will serve as the basis for the Director's decision to order a revision to an approved plan.

Section 250.34-2(l) has been modified to indicate that plan revisions which call for additional permits will be subject to coastal zone consistency review. Language has also been added to indicate that the recipients of approved development and production plans will be provided information copies of revisions of and updates to approved plans.

§ 250.34-3 Environmental Report.

Sections 250.34-3(a) and (b) have been slightly modified to clarify the nature and scope of the information that is to be included in an Environmental Report (Exploration) and (Development/Production). The principal changes are designed to make it clear that the Department does not want the lessee to duplicate information or data which is already in the possession of or readily available to the Survey office that will process the plan and review the report. The lessee is to incorporate that information or data into an Environmental Report (Exploration or Development/Production) by reference. Lessees are also required to provide information on how to obtain copies incorporated by reference.

These subsections have also been expanded to include special provisions for leases in the western Gulf of Mexico. Under these provisions the Director may, after consultation with the Office of Coastal Zone Management and the affected State(s), limit the amount of information that is required to be included in an Environmental Report, if a report is needed at all, to the information needed to make coastal zone consistency determinations.

Section 250.34-3(a)(i)(1)(G) has been restructured to state more clearly the environmental and socioeconomic considerations to be addressed in the lessee's Environmental Report. The restructuring of this paragraph has not resulted in any addition to the lessee's reporting burden.

The provisions of § 250.34-3(b)(1)(i)(A)(4) have been expanded to include the specific requirement that lessees identify the means of transportation to be used to bring wastes to shore, the disposal methods to be utilized, and the location of onshore waste disposal or treatment facilities for waste generated on the OCS that requires onshore disposal. Finally, all references to information relating to air quality have been deleted. The Department is currently completing work on regulations to implement section 5(a)(8) of the Act and envisions reincorporating air quality information requirements into 30 CFR 250.34-3 as a new subsection.

§ 250.34-4 Compliance with NEPA.

Section 250.34-4 has not been revised to include specific criteria to indicate the circumstances under which the Director will determine that approval of a development and production plan constitutes a major Federal action requiring the preparation of an EIS. Efforts to establish criteria would unnecessarily limit the discretionary authority granted the Secretary of the Interior under section 25(e)(1) of the Act. We recognize, however, the desirability of having these documents give

as comprehensive an assessment of the environmental impact of development and production activities in a given areas as is possible.

AUTHORS

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ENVIRONMENTAL IMPACT AND REGULATORY ANALYSIS STATEMENTS

The Department of the Interior has determined that this revision of the regulations in 30 CFR 250.34 does not constitute a major Federal action significantly affecting the quality of the human environment and, therefore, preparation of an Environmental Impact Statement is not required. The Department has also determined that this notice of final rule is not a significant action and does not require the preparation of a regulatory analysis under Executive Order 12044.

JOAN M. DAVENPORT,
Assistant Secretary of the Interior

SEPTEMBER 11, 1979

3. Preamble, 30 CFR 250.2, Definitions; 250.34-3, Environmental Reports; and 250.57, Air Quality; 45 FR 15128, March 7, 1980.

DEPARTMENT OF THE INTERIOR

Geological Survey

30 CFR Part 250

Oil and Gas and Sulphur Operations in the Outer Continental Shelf

AGENCY: U.S. Geological Survey, Department of the Interior.

ACTION: Final rule.

SUMMARY: This rule establishes a regulatory program to implement Section 5(a)(8) of the Outer Continental Shelf (OCS) Lands Act Amendments of 1978, Pub. L. 95-372 (herein referred to as the "Act"), concerning the regulation of air emissions from oil and gas operations on the OCS. The regulations revise 30 CFR 250.2 and 250.34 and create a new section 30 CFR 250.57.

DATE: This rule shall become effective on June 2, 1980.

ADDRESSES: A copy of this final rule may be obtained from the following offices of the Geological Survey:

Chief, Conservation Division, U. S. Geological Survey, National Center; Mail Stop 600, Reston, Virginia 22092.

Conservation Manager--Eastern Region, U.S. Geological Survey, 1725 K Street, N.W., Suite 204, Washington, D.C. 20006.

Conservation Manager--Gulf of Mexico OCS Region, U.S. Geological Survey, 336 Imperial Office Building, P.O. Box 7944, Metairie, Louisiana 70010.

Conservation Manager--Pacific OCS Region, U.S. Geological Survey, 1340 West Sixth Street, Room 160, Los Angeles, California 90017.

Conservation Manager--Alaska Region, U.S. Geological Survey, 800 "A" Street, Suite 109, Anchorage, Alaska 99501.

FOR FURTHER INFORMATION CONTACT:

John Goll, U.S. Geological Survey, National Center Mail Stop 600, Reston, Virginia 22092 (703) 860-7136.

AUTHORS: Thomas McCloskey, Office of the Assistant Secretary--Energy and Minerals, Department of the Interior, Theresa Hooks, Office of the Solicitor, Department of the Interior, R. A. Karam, Office of OCS Program Coordination, Office of Assistant Secretary--Policy, Budget and Administration, Department of the Interior, John Goll, U.S. Geological Survey, Department of the Interior.

SUPPLEMENTARY INFORMATION:

BACKGROUND

The Act requires that the Secretary of the Interior prescribe regulations with provisions for compliance with the national ambient air quality standards pursuant to the Clean Air Act (42 U.S.C. 7401 et seq.), to the extent that activities authorized under the Act significantly affect the air quality of any State (Section 5(a)(8), 43 U.S.C. 1334). By Notice of December 28, 1978, (43 FR 60612) public comments were requested to assist the Department of the Interior in the identification and selection of a regulatory program to control air emissions from activities authorized under the Act which significantly affect onshore air quality. On May 10, 1979, proposed regulations on this subject were published in the Federal Register (44 FR 27449).

COMMENTS

Fifty-five sets of comments and recommendations were submitted in response to the invitation contained in the notice of proposed rule. The comments and recommendations varied widely in nature, scope, and content. Several of the commenters included studies and analyses as part of their submission. The comments represented the views of 6 public interest and environmental groups, 20 Federal, State, and local government agencies, and 29 industry and trade organizations.

PUBLIC HEARINGS

Oral testimony relating to the proposed regulations was taken at public hearings held in Los Angeles, California on June 7, 1979, New Orleans, Louisiana on June 12, 1979, and Washington, D.C. on June 14, 1979.

DISCUSSION OF MAJOR ISSUES

1. Need for Regulations. Several commenters asserted that the promulgation of the air quality regulations is premature. They argued that no regulatory action should be taken until the Department makes a formal determination that OCS operations are having or could have significant effects on the air quality of an onshore area of a State.

The Department has rejected this argument. The procedures outlined in the final regulations are to be used to determine whether emissions from an OCS facility significantly affect an onshore area. The regulations are necessary to insure that all concerned are aware of these procedures and are advised as to how the Secretary intends to fulfill the statutory responsibilities related to the protection of onshore air quality. This approach is similar to that followed under other regulatory programs and is fully consistent with the Department's statutory mandate.

A number of commenters asserted that the regulations are excessively stringent and unnecessarily broad and complex. They argued that the regulations would delay and add unnecessary expense to the exploration for and development of OCS oil and gas resources and characterized the program as a clear case of overregulation that ignores Congressional intent and exceeds the statutory mandate. One commenter remarked that a decision to publish such complex regulations should be coupled with a commitment to establish a training program for industry. The Department believes that the regulations are reasonable, practical, and consistent with the statutory mandate. This preamble contains a detailed discussion of the regulations which explains the necessity and rationale for each regulatory requirement. Air quality considerations are complicated, particularly as they relate to the unique circumstances encountered on the OCS. However, every effort has been made to make the Department's OCS air quality regulations as clear and straightforward as possible.

Although a number of commenters expressed support for the overall regulatory framework and the adoption of significance levels and prevention of significant deterioration (PSD) increments from the Environmental Protection Agency (EPA), others argued that EPA standards and practices were inappropriate in the regulations. The Department has developed a regulatory framework which is similar, in many respects, to the one employed by EPA. The Department decided to follow EPA's program, to the maximum extent possible, because of that agency's air quality expertise. The Department's program differs in some respects, however, because the Department's mandate under the Act is different than EPA's mandate under the Clean Air Act and because offshore conditions differ from those encountered onshore. The Clean Air Act gives EPA the authority to regulate air pollution sources onshore. The Act, on the other hand, authorizes the Department to regulate OCS activities only if the emissions from the activities have significant effects on onshore air quality. Also, all OCS sources are external to the areas whose air quality they may affect, a situation not commonly encountered in EPA's regulatory program. Thus, the Department has used only those aspects of EPA's program that are adaptable to the offshore situation. In doing so, we have fulfilled the Congressional intent that the Department be "guided by the Clean Air Act, in consultation with the Environmental Protection Agency" in devising this air quality program.

One commenter requested that the final regulations explain the relationship of section 25(a)(1) of the Act to the air regulatory scheme. Section 25(a)(1) provides for the creation of a less burdensome regulatory program in the western Gulf of Mexico. Under regulations governing the submission and approval of exploration plans and development and production plans, (see 44 FR 53686, September 14, 1979) OCS leases in the western Gulf of Mexico will be treated differently from leases in other OCS areas. Environmental Reports, for example, will not be required unless an affected State has an approved coastal zone management plan. If a report is requested, the Director of the U.S. Geological Survey (GS) will allow a lessee to submit only that information the State indicates it needs to make its consistency determination. The different treatment accorded for western Gulf of Mexico leases does not, however, extend to air quality reporting and control requirements. Nothing in the language of the statute or the legislative history suggests that the provisions of Section 25(a)(1) of the Act exempt lessees from the air quality regulatory program. Section 5(a)(8) of the Act requires "compliance * * * to the extent that activities authorized under this Act significantly affect the air quality of any State." A lessee submitting a new or revised plan after June 2, 1980, will be required to submit the information needed to make the findings under § 250.57-1(d)-(i), and to take the necessary measures to control emissions regardless of whether an Environmental Report is required. Likewise, existing facilities in the Gulf of Mexico may be reviewed in the same manner as existing facilities in other parts of the OCS.

Finally, several commenters objected to the regulatory scheme because the lessee, instead of the Department, "controls" the information. These commenters criticized the "passive" role of the Department and asserted that the regulator, not the regulated, should be responsible for collecting and interpreting data and making decisions concerning the applicability of the regulations to OCS operations. We do not believe that this is an accurate characterization of the role of the Department in implementing these regulations. The regulations place initial responsibility for all information gathering on the lessee. However, the Director has clear authority to require supplementary information and to take whatever action is necessary to validate the information. Additionally, the GS will review and evaluate all

information submitted by the lessee and will make all final decisions concerning the necessity for controls and offsets.

2. Need for Regulatory Analysis. Several commenters argued that implementation of the regulations represents a significant regulatory action and, pursuant to Executive Order 12044, requires preparation of a regulatory analysis. Prior to the publication of the proposed regulations, the Department prepared a Negative Declaration and Regulatory Analysis. That document examined the criteria for determining whether the proposed regulations constituted a significant regulatory action. The Department found that: (1) Failure to promulgate rules could have a major regionwide impact on state and local governments because a failure to adequately control air emissions could affect the eligibility of state and local governments to receive Federal financial assistance. The Clean Air Act requires that state and local governments achieve national ambient air quality standards by specific dates in order to maintain eligibility for specified Federal grants; (2) The proposed regulations would impose new recordkeeping and reporting requirements on the oil and gas industry. However, the impact of these requirements was diminished for certain lessees operating in certain areas because they had already voluntarily compiled air quality information for proposed activities which corresponded to that required under the proposed regulations; (3) The proposed regulations would not involve a potential conflict between environmental and other considerations; (4) Although the proposed regulations would have a modest impact on the budget and personnel of the GS, they would not have a major impact on other programs of the Department, other Federal agencies, or the allocation of Federal funds; and (5) Based on an analysis of the projected cost to industry of complying with the proposed regulations, they were not estimated to have an annual economic consequence of $100 million or more. Based on these conclusions, the Department determined that the implementation of the regulations, as proposed, was a significant action but, because the potential cost of compliance was under $100 million, the preparation of a regulatory analysis was not required.

A review of that determination, in light of the comments received, failed to show any basis for changing the determination. In fact, the adoption of emission exemption rate formulas will reduce the overall cost of compliance by increasing the number of lessees exempt from regulatory review under the program and, thereby, decreasing the number of lessees who will have to model emissions to determine whether they produce onshore ambient air concentrations above the significant levels. We therefore maintain our finding that a regulatory analysis is not called for by the criteria set out in Executive Order 12044.

3. Exemptions. The proposed regulations exempted from further regulatory review OCS facilities with less than 100 tons per year uncontrolled emissions of each pollutant or less than 50 tons per year of controlled emissions of each pollutant. These exemption levels were applied to all facilities regardless of their distance from shore. In the preamble to the proposed regulations the Department cited an analysis by EPA which indicated that emissions of less than 100 tons per year would not cause onshore ambient concentrations of air pollutants that exceed the 24-hour, 3-hour, and 1-hour EPA significance levels. The Department also noted that although a distance exemption could be established, data were insufficient to justify such an exemption in the proposed rule.

Several commenters favored the development of an exemption formula which incorporates a distance consideration. The American Petroleum Institute (API) derived an emission rate-distance formula which received wide industry backing. API began their analysis by using EPA's emission exemption rate of 100 tons per year for a source locating in a nonattainment area. Based on assumed and observed meteorological data. API then calculated the maximum ground level ambient air concentration of emissions from the source and substituted this concentration for the EPA significance levels. Then API calculated the emission rates and offshore source distances that would produce this concentration at the shoreline. The API formula is $E=80D$, where E is emissions of air pollutants expressed in tons per year and D is distance from an onshore area expressed in miles. Thus, facilities with emissions of less than 240 tons per year at 3 miles, 800 tons per year at 10 miles, and 4,000 tons per year at 50 miles would be exempt.

Most of those who favored the adoption of the API formula said that if the Department decides to retain exemptions based on an emission rate alone, the distinction drawn between controlled and uncontrolled emissions should be dropped and the Clean Air Act exemption levels of 100 tons per year for facilities impacting nonattainment areas and 250 tons per year for facilities impacting attainment areas should be adopted. Other commenters recommended exempting facilities more than 8 miles from shore, and there was a scattering of support for more lenient emission rate exemptions (e.g. one commenter recommended 750 tons per year, and another 400 tons per year at 8 miles.)

Many commenters argued that the proposed exemption levels were not stringent enough and that when this fact is coupled with other alleged deficiencies in the proposed regulatory scheme (i.e. the recognition of atmospheric dilution, the adoption of significance levels and the absence of controls for cumulative effects), the result is insufficient protection

for the air quality of areas with more stringent State standards. They recommended the adoption of exemption levels equivalent to those allowed by the onshore jurisdiction potentially affected by emissions from offshore facilities (e.g. 25 pounds per hour, or 250 pounds per day for facilities located adjacent to many jurisdictions in California).

Emission rate-distance formulas, developed by the GS, have been incorporated into the final regulations. However, an approach different from that recommended by API has been adopted. The GS adopted an approach suggested by EPA which is designed to insure that exempt OCS facilities will not produce onshore ambient air concentrations above the adopted significance levels. Because of the decision to rely on significance levels to make the "significantly affected" determination (except for volatile organic compounds (VOC)--see "Volatile Organic Compounds"), the distance-emission rate approach designed by GS is preferable to that suggested by API.

In developing the exemption formulas, the GS assumed source characteristics and meteorological conditions similar to those encountered on the OCS. Working with the adopted significance levels, the GS then calculated, for each pollutant and averaging time, the emission rates that would produce, from OCS sources at varying distances from shore, onshore ambient air concentrations equivalent to the significance levels. Three pollutants (total suspended particulates (TSP), sulfur dioxide (SO_2) and nitrogen oxides (NO_x)) produced approximately the same results showing that a 100 tons per year emission rate for a facility located three statute miles from shore would not exceed significance levels onshore. This emission rate is the exemption level used by EPA for new sources locating in nonattainment areas onshore. Because of the higher allowed concentration for carbon monoxide, the GS developed a separate formula for carbon monoxide (CO).

The Department's exemption formulas are: $E = 3400D^{2/3}$ for CO and E = 33.3D for TSP, SO_2 NO_x and VOC (see "Volatile Organic Compounds"), where E is the emission exemption amount expressed in tons per year and D is distance from an onshore area expressed in statute miles. Under these formulas, facilities with emissions of SO_2, for example, of 100 tons or less at 3 miles 333 tons or less at 10 miles, and 1665 tons or less at 50 miles would be exempt from further air quality review.

The adopted exemption formulas are more conservative than the developed by API because they were based on different assumptions concerning the effective release height and meteorological conditions. It is important to remember that an exemption level serves only as a screen to eliminate from review those sources which, when considered alone, will have no significant effect on the air quality of any onshore area.

In response to the comments concerning the ability of the proposed regulatory scheme to protect more stringent State standards, the Department is publishing, in a separate Notice, proposed regulations which would establish a more stringent program for application to those OCS facilities located off the coast of California.

4. Modeling and Atmospheric Dilution. The proposed regulations required a lessee to model emissions other than volatile organic compounds (hereinafter called "non-VOC emissions") from a non-exempt facility to determine whether they would produce onshore ambient air concentrations above the significance levels. The lessee was required to use a model approved by EPA.

Several commenters pointed out that there is no overwater model which EPA has "approved for use." They argued that the EPA approved models, especially when they are applied to overwater conditions, have unacceptably high margins of error--being overly conservative or not conservative enough depending on the respondent. They recommended dropping the EPA approval provision to allow the use of new models which better predict overwater plume behavior and more accurately describe offshore conditions. One commenter expressed opposition to any provision which would mandate the use of a given model, and another opposed the use of models altogether. The latter commenter suggested conducting actual monitoring to determine whether emissions from an OCS facility have a significant onshore effect.

Some commenters recommended that the Department should develop a list of acceptable models for offshore application, and one commenter suggested that the acceptable model or models contain guidelines on the factors to be considered in using the model. Another commenter objected to the use of models for predicting long term impacts. This respondent argued that models are capable of predicting short term impacts but are not suited for measurement of long term impacts and recommended the development of a model validation process. A number of commenters believed that the model approval process should be expanded to include a role for States.

Many commenters also criticized the establishment of an exemption formula which incorporates a distance consideration and opposed any regulatory provision that allows the dilution of air pollutants during atmospheric transport to be considered in determining whether emissions from an offshore facility significantly affect an onshore area. They argued that such an approach is analogous to the use of tall stacks as a control measure--a technique designed to lower ground level air concentration which has not been allowed by some courts.

The Act requires that the Department devise a regulatory scheme which requires the control of emissions from OCS facilities only when these emissions would have significant effects on the air quality of an onshore area. It is the position of the Department that this compels development of a method of calculating the onshore concentration of an offshore emission. Modeling is a common and accepted method of predicting the impact of emissions on air ambient concentrations. EPA, for example, uses the results of such models for determining the applicability of certain new source requirements, such as offsets. Thus, the agency with primary responsibility for protecting the Nation's air quality recognizes the ability of the atmosphere to dilute emissions during transport, as long as excessive stack heights and other illegal dispersion techniques are not used. The Department has adopted this analysis.

The Department has retained the modeling requirement established in the proposed regulations but, in recognition of the comments received, has initiated a step-by-step process which will lead to the development of an acceptable overwater model or models. At the present time, GS is reviewing the list of EPA approved models and will select one or two which lessees must use in the air quality program. During the next year, these models will be adapted for overwater applications. Also, during the next two to three years, the Bureau of Land Management (BLM), Department of the Interior, will conduct actual field tests off the coast of southern California to develop diffusion coefficients for overwater conditions. These diffusion coefficients will be used to validate models the Director has approved for use. Finally, the GS will establish a mechanism, similar to the one used by EPA, under which interested outside parties can recommend new models or adaptations to existing models to the GS. Each recommendation will be subject to public review and comment before being added to the list of approved models.

It is the Department's position that the benefits to be derived from requiring the use of an approved model or models outweigh the loss of "flexibility" advocated by some commenters. Despite the deficiencies in existing EPA models, their use, in the short term, is preferable to the controversies that would arise if all the parties involved were allowed to pick different models to predict and analyze the onshore air quality impacts of offshore operations.

It should be noted that EPA provides information on its approved models explaining how they work and how to use them. The Survey plans to provide similar information on the models which the Director approves for use. Finally, the Department disagrees with those who contend that, although the EPA models can estimate short term impacts, they cannot estimate long term (i.e. annual) impacts. Several EPA models calculate one hour averages of relative concentrations and sum these to estimate the annual average impact of the source. Thus the long term impacts are based on the cumulative effect of short term impacts.

The Department disagrees with comments concerning the impact of atmospheric dilution in its regulatory program. Any effort to equate atmospheric dilution of offshore emissions to using tall stacks is faulty for three reasons. First, the use of models to predict onshore impacts of offshore emissions does not constitute, as the commenters suggest, a "form of emission regulation." Instead, the models are used to answer the threshold question--is there a significant impact on the air quality of an onshore area? If the models predict an impact in excess of that level which is defined as significant, then emission limitations and, in some instances, offsets are required. Second, the outcome in the "tall stack" cases cited by commenters was based on the court's interpretation of specific language in Section 110 (a)(2)(b) of the Clean Air Act, as amended (42 U.S.C. 1857c-5(a)(2)(B)). No similar language appears in the OCS Lands Act Amendments of 1978. Third, it is clear that Congress intended that the Department should consider distance in determining whether emissions from an OCS facility should be controlled:

> It is expected that some activities may not have significant effects because of distance from shore or meteorological conditions that blow the pollution out to sea. If an OCS activity or facility is determined to have no such significant effect, when, for example, it is located many miles from the coast, the requirement of the regulations under section 5(a)(8) would not apply. (see House Conf. Rep. No. 95-1474, p. 86).

This statement reflects the understanding that emissions further from shore are less likely to cause increases in the onshore ambient air concentrations than emissions released closer to the onshore area. Thus, a regulatory program which considers atmospheric dilution is consistent with this mandate.

5. Significance Levels. The proposed regulations adopted the significance levels established by EPA to control sources locating in a "clean" area but which would impact a nonattainment area. (see "Emission Offset Interpretive Ruling", 44 FR 3283 January 16, 1979). Non-VOC emissions from a non-exempt OCS facility were compared to these EPA significance levels to determine whether the emissions would significantly affect the air quality of an onshore area. These significance levels are approximately two percent of the

national ambient air quality standards and correspond closely to the Class I increments under the Prevention of Significant Deterioration (PSD) Program.

Several commenters argued that the proposed significance levels were too stringent and they recommended the adoption of levels that are 10 percent of the national ambient air quality standards. They maintained that this level would account for the natural variability of atmospheric background concentrations of the pollutants of concern and the limitations inherent in equipment and techniques which measure ambient pollutant concentrations. Other commenters, noting the relationship between the significance levels and the Class I increments, recommended basing the significance levels on on the Class II increments, which are 25% of the national ambient air quality standards. They pointed out that Class II increments apply to the areas where most people live and would be more reasonable for determining a significant effect than the Class I increments.

Other commenters argued that the significance levels are not stringent enough and that an increase in air contaminants of up to two percent of the national ambient air quality standards is too much for nonattainment areas which are struggling to meet the standards. They recommended reducing the exemption level (see "Exemptions"), eliminating the modeling requirement (see "Modeling") and the significance levels, and requiring all emissions from nonexempt facilities to be fully reduced or offset.

It is the position of the Department that the use of EPA's significance levels in these air quality regulations is prudent. To fulfill the requirements of the Act, a regulatory scheme must be designed so that offshore emissions are converted into onshore ambient air concentrations which are then measured against a criterion to determine whether the onshore air quality is sufficiently affected to warrant regulation of the offshore source. EPA encounters an analogous situation where emissions from new sources locating in "clean" areas may adversely affect a nonattainment area. To address this situation EPA established a set of significance levels and stipulated that if the emissions from the new source locating in the "clean" area would cause ambient air concentrations in excess of these levels in the actual area of nonattainment, mitigation measures are necessary. Because the onshore situation for which the EPA significance levels were designed is similar to the offshore situation, the levels have been incorporated into this regulatory program. The levels are stringent enough to assure that onshore effects from offshore operations will be inconsequential but are not overly burdensome to operators on the OCS.

6. Volatile Organic Compounds (VOCs). Under the proposed regulations, a "36-hour travel time" criterion was used to determine whether emissions of VOCs (i.e. compounds which react with other pollutants in the atmosphere to form ozone) from a non-exempt facility significantly affect the air quality of a State. The "36-hour travel time" criterion, adopted from EPA, was selected because EPA informed the Department that acceptable reactive models for calculating ozone concentrations resulting from VOC emissions from individual sources do not exist. EPA's rationale for this criterion was that most reactions leading to the formation of ozone occur during this 36-hour timeframe.

In the preamble to the proposed regulations, the Department noted that EPA was reevaluating the "36-hour travel time" criterion and might change it after the Department published its proposed or final regulations.

The Department indicated that it would evaluate any new EPA approach for inclusion in the air quality regulations. On September 5, 1979, EPA withdrew the "36-hour travel time" criterion and proposed a requirement that sources locating in attainment or unclassified areas (the location of all OCS sources) monitor for one year (or for a shorter period specified by EPA) to determine whether there is an ozone violation at the site. If at least one ozone violation occurs during the monitoring period, the source generally would be subject to all EPA regulations which apply to sources locating in nonattainment areas. If no onsite violation occurred, the source would be subject to all EPA regulations which apply to sources locating in attainment areas.

Commenters on the proposed regulations gave very little support for the retention of the "36-hour travel time" criterion. Many commenters claimed that the criterion had no scientific basis and that the regulatory requirements were difficult to understand and apply. Alternative recommended approaches included adopting any future EPA approach, treating VOCs like the other criteria pollutants, or requiring control of all non-exempt VOC sources.

The Department has dropped the "36-hour travel time" criterion and has decided against following EPA's new approach to VOC emission control. An approach has been adopted which will require control of all facilities not exempt for VOC. The Department will treat offshore VOC emissions much like EPA treats them onshore. That is to say, the exemption level of 100 tons per year at three miles will apply. Sources at distances of more than three miles from shore will be exempt in accordance with the emission exemption amount determined by using the formula E=33.3D (see Exemption). All VOC emissions which are not exempted will be controlled.

The decision not to adopt EPA's new approach was based on the belief that onsite ambient air monitoring would pose unacceptable technologic

and economic problems. It is unclear how sensitive monitoring equipment would react to the marine environment, and the placement of a monitoring buoy or tower on the OCS does not appear to be worth the cost, compared to the regulatory approach adopted. The decision not to treat VOCs like the other criteria pollutants was based on the absence of an acceptable reactive model. Should EPA approve a reactive model, the Department will reevaluate the regulations to determine the feasibility of treating VOCs as other criteria pollutants.

7. Best Available Control Technology (BACT). Under the proposed regulations, any lessee proposing a facility whose non-VOC air pollutants would significantly affect the air quality of a nonattainment area would have been required to take any measures necessary to reduce or offset the emissions from the facility so that the pollutant concentrations would not affect the nonattainment area. In determining the appropriate level of control for facilities with non-VOC emissions that significantly affect the air quality of an attainment or unclassifiable area, the lessee would follow a two-step approach.

First, the lessee would have identified BACT in the exploration plan or development and production plan. Next, assuming the application of BACT, the lessee would have modeled emissions of SO_2 and TSP to determine whether they would have produced ambient air concentrations in the attainment or unclassifiable area above the maximum allowable increments prescribed in the proposed regulations. If concentrations exceeded the maximum allowable increments, the lessee, in addition to applying BACT, would have been required to take whatever additional measures were necessary to reduce or offset the emissions down to a level at which the maximum allowable increments would not have been exceeded. The same general approach would have been followed for a facility with VOC emissions which were within 36 hours travel time of a nonattainment, attainment, or unclassifiable area. Finally, when modeling indicated that emissions from an existing or temporary facility would have significantly affected any nonattainment, attainment, or unclassifiable area of a State, the lessee would have been required to install BACT.

Many commenters complained that the imposition of the BACT requirement will impede the installation of the most cost effective technologies. They like the approach that would be followed when emissions significantly affect a nonattainment area (where some level of control less than BACT might be adequate) and complained that it is excessive to require a more stringent level of control when the same emissions significantly affect an attainment or unclassifiable area. They recommended deleting the BACT requirement and allowing the lessee to use a combination of controls and offsets to achieve the necessary reductions.

Other commenters pointed to the discrepancy between the level of control required for emissions significantly affecting a nonattainment area and those significantly affecting an attainment or unclassifiable area, and recommended modifying the regulations to more closely correspond with the level of control required by EPA in nonattainment areas (i.e. EPA's lowest achievable emission rate (LAER) standard). They did, however, support the use of BACT to control emissions significantly affecting attainment or unclassifiable areas.

The Department has decided to adopt an approach which more closely parallels the one used by EPA to control emissions which significantly affect a nonattainment area. The Department believes that it is important to require the installation of control equipment on OCS sources affecting the air quality of nonattainment areas. However, the Department has rejected the recommendation that EPA's standard of LAER be imposed on sources significantly affecting a nonattainment area. The LAER standard, unlike the BACT standard, gives no consideration to economic, environmental, or technological factors and thus conflicts with the best available and safest technologies standard contained in Section 21(b) of the Act. For this reason, the Department will require the use of BACT to control emissions which significantly affect a nonattainment area. In addition to applying BACT, a lessee of a facility which significantly affects a nonattainment area will also be required to install additional control equipment, obtain offsets, in order to fully reduce the emissions from the facility. For example, assume that a facility is found to significantly affect a nonattainment area, and that the total emissions of a particular air pollutant which must be fully reduced are 500 tons per year. Under the final regulations the lessee first must apply BACT. Assume that the installation of BACT reduces the emission of the pollutant down to 200 tons per year. In this instance, the lessee would then be required to install additional control equipment or obtain offsets (or a combination of the two) to fully reduce or offset the remaining emissions attributable to the facility by 200 tons.

The Department has also retained the requirement that BACT be applied when emissions would significantly affect an attainment area and when emissions from a temporary facility would significantly affect an nonattainment, attainment, or unclassified area. Additionally, the installation of BACT may be required, in some instances, for existing facilities.

8. Prevention of Significant Deterioration (PSD). The proposed regulations required lessees to control emissions from facilities which significantly affect the air quality of onshore areas where the air quality is better than the

primary or secondary ambient air quality standards.

A number of commenters argued that the Secretary does not have the authority, under Section 5(a)(8) of the Act, to include PSD requirements in the regulations. They asserted that the statutory language, which mandates "compliance with the national ambient air quality standards," limits the Department's regulatory authority to those onshore situations where the primary and secondary ambient air quality standards, established by the Clean Air Act, are being violated. They also asserted that the regulatory program established for nonattainment areas is totally separate and independent of the PSD regulatory program and that by using the term "national ambient air quality standards" Congress was referring only to the nonattainment program. Finally, some commenters pointed out that the offshore operations, unlike land based operations, usually are confined to the location where the oil or gas are discovered and cannot be relocated.

Other commenters, however, supported the impositon of controls on OCS facilities which significantly affect attainment or unclassifiable areas. They argued that the legislative history clearly indicates that the Department's regulations must insure that OCS sources will not have an adverse effect upon the air quality or attainment areas. One commenter pointed out that the PSD increments are federally-established and nationally applicable standards for attainment areas and operate in much the same way as the primary and secondary standards operate for nonattainment areas. Further, they argued that the PSD program, when incorporated into the State Implementation Plan, becomes a more stringent State program which, according to the Conference Report, must not be adversely affected by the offshore drilling program. Another commenter agreed that the PSD program should be included in the final regulations, but complained that the regulatory scheme as proposed is not sufficiently stringent. The commenter suggested that all OCS facilities should be required to install LAER whether or not the facility would significantly affect an attainment or nonattainment area. This commenter also asserted that in order to prevent the significant deterioration of onshore air quality, it would be necessary for the Department to require in all cases, the modeling of cumulative impacts.

Also, one commenter believed that the proposed rules failed to recognize that some of the allowable increment may have been consumed by other new sources which have previously been located in an area. This commenter also argued that the OCS facility should not be allowed to consume the entire PSD increment because the clean air area would then be put at the same economic disadvantage as a nonattainment area when attempting to site new sources. The commenter recommended that the regulations should limit the offshore facilities to a certain percentage of the annual and short term increment (25 percent and 75 percent, respectively). Finally, one commenter suggested that the decision on the PSD requirements be delayed until the D.C. Court of Appeals issued its final ruling in Alabama Power Co. v. Costle.

After carefully considering the arguments presented by the many commenters, the Department has decided that it is legally authorized to retain the provisions which require compliance with standards established by EPA to prevent the significant deterioration of onshore air quality in attainment areas.

The Department believes that commenters are mistaken in their argument that, because of the statutory reference to "national ambient air quality standards," the authority of the Secretary is limited to control of OCS emissions affecting the air quality of nonattainment areas. We believe that Congress used the term "national ambient air quality standards pursuant to the Clean Air Act" in a broad sense to mean that the Secretary should promulgate regulations which insure the protection of air quality in attainment as well as nonattainment areas from degradation resulting from emissions from OCS operations. This interpretation is entirely consistent with the intent of Congress as expressed in the legislative history. Statements made on the House floor during the debate over the air quality provisions of the Act clearly demonstrate that Congress intended that all applicable aspects of the air quality regulatory program established under the Clean Air Act be extended to the program established under the Act (see 1978 Cong. Rec. H. 415-416, January 31, 1978). That the provisions of Part C of the Clean Air Act are "applicable" is underscored by the debates which occurred among the conferees during Conference Committee meetings. The point was made emphatically that if emissions from offshore operations are not regulated to the same extent as emissions from onshore operations, then onshore growth will be slowed in favor of offshore development (see Transcript of Conference Committee on OCS Lands Act Amendments, June 19, 1978). No distinction was made between attainment and nonattainment areas, strongly suggesting that Congress had no intention of creating a special exemption for offshore operations significantly affecting the air quality of an attainment area. Indeed, the legislative history indicates that once it is determined that offshore emissions significantly affect the air quality of onshore areas, these emissions are to be regulated regardless of attainment status.

The commenter who argued that the regulations fail to recognize that some of the allowable increases may have already been consumed is mistaken. The regulations clearly indicate that the "maximum allowable increases" for SO_2

and TSP are ceilings which cannot be exceeded within the applicable area. To calculate the acceptable emmission level, a lessee must combine the ambient air concentrations resulting from the projected emissions of TSP and SO_2 from the proposed OCS facility with those emissions of TSP and SO_2 from other onshore and offshore sources which contribute to the consumption of the maximum allowable increases.

The Department has rejected the suggestion that a lessee be limited to a percentage of the maximum allowable increases. Since EPA has not established this requirement for onshore sources, the Department has decided not to impose such a requirement on offshore operations. Finally, the D.C. Court of Appeals issued its final ruling in Alabama Power v. Costle on December 14, 1979. These final regulations contain no provisions or requirements which conflict with the ruling in that case.

9. Offsets. Under the proposed regulations, the lessees were allowed to use offsets instead of controls to reduce the emissions significantly affecting an onshore nonattainment area. In each instance, the lessee would be given a choice between the use of controls or offsets, or a combination of the two.

Several commenters questioned the Department's authority to require emission offsets from onshore facilities since these facilities are outside the Department's jurisdiction under the Act. Other commenters, who supported giving the lessees the choice of controlling or offsetting emissions, argued that the amount of offset required should be only that necessary to reduce the emissions to that level which would prevent violations of the national ambient air quality standards. They also argued that offsets should never be necessary where only an attainment area is affected. Finally, some commenters argued that the Department should require greater than one-to-one (1:1) offsets when emissions significantly affect nonattainment areas.

The Department has retained offset provisions in its final regulations. The offset requirement is discretionary; no absolute requirement for onshore offsets exists in the final regulations. Instead, lessees are given the choice, after the application of BACT (see "Best Available Control Technology"), of installing additional controls or obtaining onshore or offshore offsets.

It is the position of the Department that it would be unwise to limit the use of offsets as the commenters recommended. The decision to require full reduction of emissions which affect the air quality of nonattainment areas (through the application of BACT and whatever additional controls or offsets are necessary) is consistent with EPA's regulatory program. The provision regarding the use of offsets to prevent a violation of the PSD increments is consistent with EPA's program and is reasonable because it provides lessees with an alternative to installing more control equipment.

Finally, the Department has rejected the recommendation that the offset requirement for emissions significantly affecting a nonattainment area should be greater than 1:1. The Department believes that such a requirement would conflict with its legislative mandate. The Department is limited in preventing significant onshore effects and cannot impose a level of control which would leave the air cleaner, in effect, than it would have been if the OCS facility had never located offshore.

10. Temporary Facilities. The proposed regulations contained a definition of "temporary activities" which indicated that construction and drilling activities that occur in one location for less than three years would be considered temporary. The proposed rule required a lessee to apply BACT to temporary activities which significantly affect the air quality of any state.

Several commenters supported this approach. Others agreed with the BACT requirement but recommended shortening the timeframe provided in the definition of "temporary activities" from three years to one year. One respondent noted that EPA uses a two year exemption period onshore and suggested that two years is also appropriate offshore.

Many other commenters argued for a total exemption of all temporary activities, including all mobile drilling equipment and pipeline and platform construction activities, from the regulatory requirements. They asserted that extensive experience has shown that temporary facilities have no adverse onshore air quality impacts. They argued that the cost of regulating temporary activities is far greater than the benefits and reiterated that onshore temporary activities are exempt under EPA's regulations. Finally, several commenters took the position that temporary facilities, if regulated at all, should only be regulated if they affect nonattainment areas.

The Department has decided to retain the approach to the regulation of temporary facilities which appeared in the proposed regulations. First, the Act does not distinguish between temporary and permanent facilities; it directs the Secretary to control all activities authorized under the Act that would have significant effects on onshore air quality. In fact, Section 11(c)(1) of the Act specifically directs the Secretary to insure that air quality impacts from exploratory activities do not have adverse effects on a State's air quality. Second, the information available to the Department indicates that substantial emissions (in excess of 100 tons per year) may be associated with temporary drilling activities.

Finally, application of the BACT requirement to temporary facilities is consistent with EPA

practices in that temporary activities are exempt from other regulatory requirements but, nevertheless, must install BACT. The Department's approach is different, however, from EPA's because OCS lessees will be required to install BACT only if their temporary activities cause significant onshore effects. Only the BACT level of control is required for temporary facilities, and not more stringent controls or offsets, because of the limited time that these activities will emit pollutants and the difficulties and inequities that would be involved in obtaining offsets for temporary facilities.

The Department also intends to retain a definition of "temporary facility" which includes exploration and development drilling activities which are conducted in one location for less than three years. The definition also encompasses construction activities. The decision to classify construction activities as temporary was adopted from EPA's regulations. The three year time frame is based on the GS's experience with the time normally associated with exploration or development drilling activities.

11. Existing Facilities. Under the proposed regulations, an activity which had commenced operations prior to the effective date of the final regulations was subject to control if an affected State could demonstrate, and subsequent analyses would affirm, that emissions from the facility were significantly affecting the air quality of an onshore area. The criteria used to make the necessary determinations were the same as those applied to new or modified facilities, but the maximum level of control was different. Existing facilities with emissions which significantly affect onshore areas were required only to apply BACT.

Many commenters argued that existing facilities should be exempt from any regulatory requirements related to air emissions. They argued that Congress did not intend to regulate emissions from existing facilities, that retrofitting existing facilities is very difficult and expensive, and that existing facilities are not known to have any detectable impact on onshore air quality.

The Department has retained the regulatory requirements of the proposed rules which are applicable to existing facilities. There is no evidence to suggest that Congress intended to exempt existing facilities from the regulatory program. Section 5(a)(8) of the Act draws no distinction between existing and proposed facilities. Indeed, section 5(a) of the Act specifically states that rules and regulations promulgated under the Act shall apply as of their effective date, to all operations conducted under a lease issued or maintained under the provisions of the Act. The House Conference Report explains this language by stating that regulations are to be applicable to any lease in effect at the date of promulgation, as well as to any lease to be let in the future (see House Conf. Rep. No. 95-1474 p. 82).

The Department believes that the approach adopted gives adequate consideration to the problems associated with retrofitting existing facilities, particularly since the application of BACT takes into account economic factors.

12. Cumulative Effects. The proposed regulations contained no specific provisions addressing the possible cumulative effects of sources locating in close proximity to each other. Numerous commenters argued that the final regulations must address more adequately the problem of cumulative effects. The Department's analysis of technical reports submitted to substantiate both sides on this issue convinced us that, in certain infrequent instances, it is possible for emissions from OCS sources to interact in such a way as to increase notably onshore ambient air concentrations of pollutants. Spacing of facilities is such, however, that it would be unusual for this to occur. However, to insure that cumulative effects are recognized and, if necessary, regulated, a provision has been added to the final regulations which gives the Director the authority to require a lessee to use models which demonstrate the effect on onshore air quality of emissions from a proposed OCS facility in combination with emissions from other OCS facilities in the area. Thus, the Director can require the lessee to use multisource models to provide information concerning cumulative effects.

Additionally, a section has been added which provides that if a State demonstrates to the Director that emissions from an otherwise exempt facility will, either individually or in combination with other OCS emissions, significantly affect the air quality of an onshore area, or the Director believes that an otherwise exempt facility may cause significantly air quality effects onshore, the Director may require the lessee to submit additional information. This provision was added to address the situation in which a State or the Director believes that an OCS facillity is having significant impacts on the air quality of an onshore area even though the emissions from the facility are below the exemption level. This might occur if the emissions from the facility are acting in combination with emissions from a nearby OCS facility to cause cumulative impacts. It is the position of the Department that the incorporation of these provisions insures that cumulative impacts of OCS facilities on the air quality of onshore areas will be identified and effectively controlled.

SECTION-BY-SECTION DISCUSSION

1. Section 250.2 Definitions

Attainment areas.—One commenter urged that the definition of "attainment area" be rephrased to make it absolutely clear that an area can be "in attainment" for one pollutant and "in nonattainment" for another. The definition that appeared in the proposed regulations and that has been adopted in the final regulations is the same as EPA's definition. Retention of this definition is important because the final regulations incorporate most of EPA's PSD program and the classification system employed by the two agencies must be consistent. In any case, the definition is sufficiently clear to indicate that an area may be in attainment status for one air pollutant and in nonattainment status for another air pollutant.

Best Available Control Technology (BACT).—Several commenters raised objections to the definition of "best available control technology". One respondent urged the Department to adopt, word for word, EPA's definition of BACT. Another argued that the definition of BACT should not encompass production processes. One commenter argued that the BACT definition should be modified to recognize the paramount importance of safety and economic factors and space and weight limitations on OCS facilities. This person recommended allowing BACT certification of individual rigs and other portable equipment. Finally, one respondent suggested that lessees should be required to identify and justify the technology chosen only if the GS has specifically identified BACT equipment which the lessee does not propose to use.

The Department has decided to modify its definition of BACT to more closely parallel EPA's definition. The definition in the proposed regulations gave the mistaken impression that methods, such as offsets, which do not result in an actual decrease in emissions could be employed to satisfy the BACT requirement. This is not the case and language has been added to make this clear. The BACT determination process was chosen because it gives recognition to energy, environmental, and economic impacts and other costs. The Department recognizes the space and weight limitations on OCS facilities and will consider these and other factors in the BACT determination process. The Department also believes that it is appropriate, particularly in the initial stages, for lessees to identify BACT. As time goes on, certain technologies, methods systems, and techniques will be recognized as BACT, and the burden of identifying BACT will be reduced.

In developing these regulations, the Department must comply with the provisions of Section 21(b) of the Act which requires, "on all new drilling and production operations and, wherever practicable, on existing operations, the use of the best available and safest technologies which the Secretary determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Secretary determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies." Control equipment installed to satisfy the BACT requirement will be deemed to satisfy the Department's best available and safest technology requirement as well.

Commence, Facilities and Source.—The proposed regulations contained the terms "activities", "facilities", "sources", and "commenced", but none of these terms was defined. The absence of definitions for these terms, and the way they were used throughout the proposed regulations, confused reviewers. A number of commenters suggested that definitions of these terms be included in the final regulations. Several felt that the term "facilities" should be substituted for the word "activities". Others suggested that "activity" should be defined as broadly as possible to avoid situations where a number of individual activities in close proximity to each other, which in aggregate may have a significant onshore impact, are exempt from the regulatory requirement. One commenter believed that the term "activity" should be defined to include all emissions at an individual platform and should include emissions from ships and barges associated with the platform. Several commenters suggested that "facility" be defined as all emission points on an individual platform and "source" be defined as each specific piece of equipment that results in emissions. Another recommended that "OCS activity" and "facility" both be defined as "an installation including all platforms joined above water."

In response to these comments the term "facility" has been substituted for the term "activities" and definitions of the terms "facility" and "source" have been incorporated into the regulations. A platform and all equipment directly associated with a platform will be considered to be one facility. Each emission point on the facility is a source.

Multiple installations or devices may be considered part of a single facility if they are related directly to the production of oil or gas from a single site. Emissions from an offshore storage and treatment unit are to be treated as if from a source that is part of the facility. Also, vessels used to transfer production away from a facility on the OCS shall be considered part of the facility for the entire period of time that the vessel is moored or otherwise physically attached to the facility. Thus, for purposes of calculating the total emissions, all emissions from such a vessel must be treated as emissions from a

source on the facility during that period in which the vessel is physically attached to the facility. Sources on support vessels other than vessels used to transfer production from a facility will not be considered part of the facility.

The term "commenced" has been deleted from the regulations and a definition of "existing facility" has been added to establish a more precise criterion that the GS will apply to determine whether a facility is regulated by § 250.57-1 or § 250.57-2.

Onshore Area of a State.—One commenter suggested that the definition of "onshore area of a State" be extended to the three mile territorial limit of the State rather than landward of the mean high water mark. According to the commenter this is necessary because air pollutants can be deposited on surface waters.

The Department has not made this change because it would conflict with the intent of Congress. The primary concern under section 5(a)(8) is the protection of the air quality of onshore areas of the States. This is evidenced by language in the Conference Report which states "(T)he standards of applicability the conferees intended * * * is that when a determination is made that offshore operations may have or are having a significant effect on the air quality of an adjacent onshore area * * * regulations are to be promulgated." Accordingly, the Department believes that it is appropriate to measure the impact of the offshore emission landward of the shoreline instead of at the 3-mile territorial limit.

Projected Emissions.--The final regulations contain a definition of the term "projected emissions". This change was incorporated in response to many commenters who questioned the validity of the distinction drawn in the proposed regulations between controlled and uncontrolled emissions. They pointed out that the D.C. Circuit Court of Appeals in Alabama Power Co. v. Costle, No. 78-1006, (D.C. Cir. 1979) (Summary Opinion, June 18, 1979; final decision December 14, 1979) invalidated an EPA regulation which required calculation of emissions based on uncontrolled emissions. The Court held that the "potential to emit" of a source must be calculated on the basis of the actual levels of emissions which would result after the application of whatever air pollution control equipment may be incorporated into the design of the facility. The Department agrees with the commenters that, in light of the court's opinion, it would be inappropriate for its air quality regulations to distinguish between controlled and uncontrolled emissions. Accordingly, the term "projected emissions" was added to clarify the basis for calculating emissions from OCS facilities.

Volatile Organic Compound (VOC).--Several commenters suggested that the definition of "Volatile Organic Compound" be modified to exclude methane and ethane. Another recommended that the definition should create an exception for carbon monoxide, carbon dioxide, carbonic acid, metallic carbides and carbonates, and ammonium carbonate. Finally, two commenters recommended a change in the definition to make it clear that the unreactive compounds specified are exempt, in all cases, from the definition.

The Department has adopted the recommendation that the exempt status of the unreactive compounds be clarified by changing the term "may be exempt" to "are exempt". However, the definition has not been changed to name the exempt unreactive hydrocarbons or to expand the list. The definition provides that unreactive compounds specified by EPA in Table 1 of 42 FR 35314, July 8, 1977 are not to be treated as volatile organic compounds. This list includes methane; ethane; 1,1,1-Trichloroethane (Methyl Chloroform); and Trichlorotrifloroethane (Freon 113). Because this table is referenced, methane and ethane clearly are excluded from the definition. The reference to the EPA table has been retained so that future changes in the table will be incorporated automatically into these regulations.

2. Section 250.34-3 Information Requirements

This section requires the submission of air pollution emission data as a part of the exploration plans or development and production plans which must be submitted and approved under 30 CFR 250.34 prior to the initiation of exploration, development, or production activities on any leased OCS area. One commenter objected to making air quality determinations a part of the plan approval process. This commenter suggested that the proper time for a decision is during the preparation of the environmental impact statement for each lease sale. This suggestion is impractical. The onshore effects of offshore operations cannot be assessed adequately until detailed information about each facility, such as the exact distance from shore and the number of wells and type of generators to be used, is available. This type of information is not available until after a lease sale. For this reason a case-by-case examination of the potential of each facility to significantly affect the air quality of onshore areas is necessary at the time that detailed plans for exploration or development and production activities on the lease are submitted.

Several commenters urged that the Department reduce the information requirements to the minimum necessary to determine whether emission controls are required. They referred to the President's recent Executive Order No. 12044 which calls for regulations to be as simple and clear as possible. The regulations are designed to comply with the President's order by elimi-

nating all unnecessary reporting. To implement this, the regulations state that the lessee is required to submit only that information needed to make the requisite findings under the regulatory program. Thus, a lessee who finds that emissions from the proposed facility fall under the exemption level would not be required to provide any further information because it would be clear, as a result of calculating the projected emissions, that no emission control is required. In addition, 30 CFR 250.34-3(a) and 250.34-3(b) allow a lessee to reference information in earlier Environmental Reports prepared for the geographic area by identifying the information and indicating a source for obtaining copies of the cited materials. Thus it is necessary for the lessee to resubmit information which has appeared in earlier Environmental Reports. For these reasons, the Department has rejected the suggestion of one commenter that the lessee be required, in every instance, to provide all the information listed in § 250.34-3(a)(4)(ii).

Several commenters recommended deletion of the provisions requiring a lessee to provide information on each onshore source of air pollution associated with the proposed offshore facility. They argued that the requirement for information about onshore emissions is duplicative, irrelevant, and not within the authority of the Secretary. This information requirement first appeared in the January 1978 regulations issued by the Department of Interior (30 CFR 250.34, 43 FR 3880) as a result of an agreement between the Department and the National Oceanic and Atmospheric Administration. The regulations required the submission of air quality information to assist States with approved coastal zone management programs in evaluating consistency determinations. It has been included in these regulations for that same purpose.

One commenter urged that the regulations clarify the meaning of the term "load factor," which appeared in the proposed regulations in the information requirements section. The term "load factor" has been eliminated from the final regulations. To calculate whether a projected emission is exempt from control under the regulations, the lessee must use the anticipated highest annual total emissions from each facility for each air pollutant.

One commenter recommended that lessees be required to note specifically which emission factors were used in the calculation of the projected emissions. The regulations require that the lessee describe the bases of all calculations; this would include the emission factors used.

Several comments were received concerning the provision in the proposed regulations requiring the lessee to identify any emission reduction control technology which exists that would achieve a greater reduction in emissions than the technology the lessee proposes to use and present the reasons why the lessee should not be required to use this technology. One commenter argued that such a requirement is unnecessary and unreasonable. Other commenters, on the other hand, supported this requirement. The requirement for submitting information on alternative control technologies has been deleted in the final regulations. However, the lessee is required to explain the basis for the technology proposed as BACT. This would include a discussion of alternative technologies.

One commenter asserted that operators in the Western Gulf of Mexico should be required to submit air quality information regardless of their Environmental Report exemption status. The Department agrees with this comment and has incorporated language in §§ 250.34-1(a)(2) and 250.34-2(a)(3) to indicate that the Director has the authority to require such information in the absence of an Environmental Report.

Several other changes have been made in §§ 250.34-3(a)(4)(ii)(A) and 250.34-3(b)(4)(ii)(A) related to the calculation of projected emissions from a facility. The requirement for expressing the emission from each source in "maximum anticipated pounds per hour" has been eliminated. Instead, for facilities described in development and production plans, a requirement for a frequency distribution of total emission from a facility, expressed in pounds per day, is included. This change enables the Department to evaluate whether any short term fluctuations in emissions from development and production facilities could cause problems. Additionally, lessees proposing modifications to existing facilities are required to submit information on both the incremental amount of the modified emissions and the total of any new and pre-existing emissions from the modified facility. This language was added to make it clear that when a lessee adds one or more new sources to an existing facility, the total emissions from the facility must be recalculated to determine whether the exemption levels are exceeded. In adopting this approach the Department rejected the suggestion of some commenters that only the additional emissions resulting from the new sources on the existing facility be considered in calculating whether emissions significantly affect the air quality of an onshore area. If this suggestion were adopted, modificatons could result in emissions which, when considered alone, would be under the exemption levels but which would cause, when combined with the existing emissions, significant effects on a State's air quality. The Department chose to require an analysis of the total emissions from a modified facility to insure adequate long term protection of onshore air quality.

A provision has been added which indicates that the Director may require a lessee to use models which demonstrate the onshore effect of

emissions from a proposed facility in combination with the emissions from other OCS facilities in the area (see "Cumulative Effects").

The final regulations indicate that models must be approved by the Director instead of by EPA (see "Models") and require the use of the best meteorological information and data available. Many commenters legitimately pointed out that the quantity and quality of meteorological information and data vary from area to area and that the proposed regulations, which cited EPA's "Guidelines on Air Quality Models," did not give any direction on what type of information or data would be required. The new language is designed to provide the necessary direction.

3. Section 250.57-1 <u>Facilities Described in a New or Revised Exploration Plan or Development and Production Plan</u>

Sections 250.57-1(a) and (c) provide that all new or modified exploration plans and development and production plans deemed submitted under §§ 250.34-1(a) or 250.34-2(a) on or after June 2, 1980 shall be subject to the regulatory program established in § 250.57-1.

Section 250.57-1(b) authorizes the Director to review any exploration plan and development and production plan which was deemed submitted or approved by GS prior to June 2, 1980 to determine whether any facility described in such a plan should, because it has the potential to significantly affect onshore air quality, be subject to § 250.57-1. It also sets forth some general criteria which the Director shall apply in determining whether this review should be conducted and whether the facility reviewed should be subject to § 250.57-1. Any facility deemed submitted or approved prior to June 2, 1980 which is identified by the Director, on the basis of the criteria, as having the potential to significantly affect the air quality of an onshore area of any State shall be required to submit the information specified in § 250.34-3(a)(4) or § 250.34-3(b)(4) and comply with the applicable requirements of § 250.57-1.

Many commenters argued that the regulations should not apply to activities covered under an approved exploration plan or development or production plan. Other commenters indicated their strong support for the revision of such plans but suggested that the language of the regulations be clarified to insure that there was no confusion on this issue.

In order to clarify the ambiguities of the proposed regulations and to respond to commenter's criticisms, §§ 250.57-1(a), (b) and (c) have been substantially revised. First, the reference to the filing of plans prior to the effective date of the regulations has been deleted. Instead, to be consistent with §§ 250.34-1(a)(6) and 250.34-2(b)(6), the term filing" has been deleted and the term "deemed submitted" has been added. The status of a plan is to be determined by the date that the plan is deemed submitted by the GS. Additionally, instead of referring to the "effective date of these regulations," the actual effective date--June 2, 1980--has been incorporated into the regulations.

The second major change from the proposed regulatory scheme concerns facilities described in development and production plans deemed submitted or approved prior to June 2, 1980, which have the potential to significantly affect onshore air quality. The overall goal of the Department's air quality program is to prevent significant onshore air quality effects from OCS facilities. Several major emission sources covered under development and production plans which have already received GS approval have not yet commenced operations. Also, the possibility exists that some plans which are deemed submitted before these regulations become effective may cover sources which have the potential to significantly affect the air quality of an onshore area. The release of emissions from these sources could result in substantial adverse onshore air quality effects. To avoid such effects, the regulations have been structured to give the Director the discretion to require that plans which were deemed submitted or approved by the GS prior to June 2, 1980 (existing facilities) be subject to the provisions of § 250.57-1 instead of § 250.57-2.

To determine whether such a facility should be treated as a new facility under § 250.57-1 or an existing facility under § 250.57-2, the Director will consider the size of the facility, the distance of the facility from shore, the number of sources planned for the facility and their operational status; and the air quality status of the onshore area. It is the intent of the Department that use of this discretionary authority will generally be restricted to those situations where a large emission source, which is part of a facility located rather close to a nonattainment area, has not yet commenced operations. For instance, it is possible that some facilities in the Santa Barbara Channel and possibly in other OCS areas off California will be subject to review under this provision.

It should be noted that the discretion created under this section is sufficient to allow the Director to review any existing facility, regardless of the operational status of the sources on the facility, if the Director has reason to believe, after evaluation of the facility according to the criteria set out in § 250.57-1(b)(1), that the facility may be significantly affecting the air quality of an onshore area. However, we believe that the Director will rarely have reason to exercise the authority under § 250.57-1(b) for existing facilities on which most or all of the sources are operating. Such existing facilities will,

however, be subject to State review as described in § 250.57-2.

Section 250.57-1(d) establishes the formulas to be used in determining whether projected emissions from a facility are exempt from the regulatory program. For a detailed discussion of these provisions, see "Exemptions."

Section 250.57-1(e) identifies the "significance levels." For a discussion of this provision, see "Significance Levels."

Section 250.57-1(f) explains how significance determinations will be made for non-VOC pollutants and for VOC pollutants. For non-VOC pollutants, any emission which would result in an onshore ambient air concentration above the significance level for that pollutant is deemed to "significantly affect" the air quality of an onshore area. For VOC's, any emission in excess of the exemption level "E" is deemed to significantly affect the air quality of an onshore area. The rationale for choosing these levels and a discussion of the comments received on this issue are included in other sections of this preamble (see "Modeling", "Significance Levels" and "Volatile Organic Compounds.")

Section 250.57-1(g)(1) requires lessees to fully reduce any non-VOC pollutant which significantly affects a nonattainment area. This must be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or the acquisition of offshore or onshore offsets. A discussion of the comments received concerning the application of BACT and the offset requirements is included in another section of this preamble (see "Best Available Control Technology" and "Offsets").

Section 250.57-1(g)(2) requires lessees to apply BACT to control non-VOC emissions significantly affecting attainment or unclassifiable areas. Assuming the application of BACT, the lessee is then directed to model emissions to determine whether the emissions of TSP or SO_2 which remain after the application of BACT would cause the PSD maximum allowable increases (established in the Clean Air Act) to be exceeded. If the increases are exceeded, the lessee must apply additional emission controls or obtain offsets so that the concentrations of TSP and SO_2 in the onshore ambient air of an attainment area do not exceed the maximum allowable increases.

The reference to the EPA regulations (40 CFR 52.21(d) and (f)), which appeared in the proposed regulations, has been deleted. The provisions of 40 CFR 52.21(f) apply to onshore areas and are independent of OCS operations. However, the provision of 40 CFR 52.21(d) has been retained and incorporated into the regulations.

Section 250.57-1(g)(3) provides that VOC emissions, except those from a temporary facility, which significantly affect a non-attainment area shall be fully reduced. The lessee must apply BACT to the facility and, if further reductions are necessary, the lessee must apply additional controls or obtain onshore or offshore offsets. This section also requires that VOC emissions which significantly affect an attainment area be reduced through the application of BACT. For a detailed discussion of these decisions, see "Volatile Organic Compounds."

A new § 250.57-1(g)(4) has been added which provides that, in those instances when emissions from a facility significantly affect both a nonattainment and an attainment or unclassifiable area, the regulatory requirements applicable to emissions significantly affecting a nonattainment area shall apply. This section also includes a requirement that in those instances when emissions from a facility significantly affect more than one class of attaiment area, the lessee must reduce emissions to meet the maximum allowable increases specified for each class. For example, if emissions from a facility simultaneously impact both Class I and Class II areas, the emissions must be reduced to the point where the maximum allowable increases are not exceeded in either area.

Section 250.57-1(h) contains the provisions which apply to temporary facilities. Under this section lessees must apply the best available control technology to reduce emissions from temporary facilities which significantly affect the air quality of a State. For a discussion of the comments received on this issue, see "Temporary Facilities."

Section 250.57-1(i) sets forth certain requirements for emission offsets. In order to obtain approval of a proposed emission offset, the lessee must demonstrate that: (1) The offsets are equivalent in nature and quantity to the emissions that must be reduced; (2) a binding commitment exists between the lessee and the owner of each offsetting source; (3) the appropriate air quality control jurisdiction has been notified of the need to revise the State Implementation Plan to include the information regarding the offsets; and (4) the required offsets come from sources which affect the air quality of the area significantly affected by the lessee's OCS operations. One commenter recommended dropping the provision requiring offsets "equivalent in nature and quantity to the emissions that must be reduced." Instead, the commenter suggested that the amount of the offset required should be limited to the equivalent of the onshore impact of the emission. Another commenter argued that the requirement that the lessee obtain binding commitments be eliminated because such a requirement could lead to delays and uncertainties and because changes at the offsetting source could adversely affect the binding commitment. Both the "equivalency" requirement and the binding commitment requirement have been retained in the final regulations. The "equiva-

lency" requirement is the same as EPA's and is necessary to insure the effectiveness of the offsets. The Department agrees that, in some instances, a change in status of the offsetting source which affects the binding commitment could occur, but believes that such a contingency can be addressed easily in the document creating the commitment.

Many comments were received on the question of whether the regulations should require that all existing onshore or offshore sources owned and operated by the lessee be in compliance with all Clean Air Act requirements as a condition to operating on the OCS. Most commenters believed that the Secretary has no authority under the Act to impose such a requirement and that such action would result in a total bar of OCS activities. One commenter, however, took the position that the cross-compliance requirement is necessary. Since onshore violations of the Clean Air Act already are subject to a variety of enforcement actions and these actions are outside the Department's jurisdiction and control, the Department believes that it is unnecessary to impose this additional condition to OCS development. Accordingly, no cross-compliance requirement has been incorporated into the final regulations.

A new § 250.57-1(j), which is similar to a provision appearing at § 250.57-1(c) of the proposed regulations, has been added. It provides that if a State demonstrates to the Director that emissions from an exempt OCS facility will, either individually or in combination with emissions from other OCS facilities, significantly affect the air quality of an onshore area, or the Director believes that an otherwise exempt facility may cause onshore significant effects, the Director may require the lessee to submit additional information to determine whether control measures are necessary. The Director will provide the lessee involved an opportunity to comment on the State's information.

Several commenters argued that this provision constitutes an impermissible delegation of authority to States. Other commenters suggested that lessees should have the opportunity to rebut information supplied by the State to demonstrate that emissions from exempt facilities are not resulting in significant onshore impacts. Others suggested that if States are allowed to intervene they must be required to carry a heavy burden of proof and provide substantial technical evidence to support their position.

It is the Department's position that the provision giving the States the opportunity to present information about the impact of otherwise exempt emissions is not a delegation of authority because the final decision concerning onshore impacts remains with the Director, not the States. However, the Department has incorporated language allowing the lessee to respond to the presentation provided by a State before the Director makes a decision concerning the necessity for the submission of further information by the lessee.

Section 250.57-1(k) is a new provision which requires the lessee to monitor, in a manner approved or prescribed by the Director, emissions from a facility. This information is to be provided in a manner and form approved or prescribed by the Director and to be included in the monthly report of operations required under 30 CFR 250.93.

The proposed regulations contained no monitoring requirements. Several commenters noted the absence of the requirement and urged that both preconstruction site-specific data and post-construction monitoring data be required to validate the analysis and the modeling. Other commenters argued that monitoring should be required only where emissions cannot be adequately estimated. These commenters were concerned with the costs and need for monitoring.

The Department must have a means of insuring that the actual emissions from a facility are the same as the projected emissions contained in the plan. This type of verification is essential for effective enforcement and to assure coastal areas that emissions from offshore facilities are not significantly affecting their air quality. Thus, the final regulations impose a post-construction monitoring requirement on any lessee that has installed emission controls. The Director must approve the form and manner in which the monitoring is to be performed. The Department expects that these requirements will vary from case to case.

Section 250.57-1(l) is a new provision under which the Director may require lessees to collect, for a period of time and in a manner approved or prescribed by the Director, and submit meteorological data from the facility.

The proposed regulations contained no requirements for the collection of meterological data by lessees. Some commenters urged that site-specific data be required as a pre-requisite to approval of a facility. It also was argued that pre-construction collection of meteorological data would be virtually impossible. Others pointed out that until the platform is constructed, the collection of meteorological data would be extremely costly.

The Department believes that onsite monitoring of meteorological conditions is not economically feasible prior to the construction of a structure on the lease area. However, once a structure is in place, the Director may impose a requirement that meteorological data be collected and reported for a specified period of time.

4. Section 250.57-2 Existing Facilities

Under the final regulations, an existing facility is defined as an OCS facility described in a plan deemed submitted prior to June 2, 1980, except for a facility identified for review by the Director under § 250.57-1(b). Operators of existing facilities are not required automatically to submit information regarding emissions. However, the Director may require the submission of this information under § 250.57-1(b) (see discussion under "Facilities Described in a New or Revised Exploration Plan or Development and Production Plan"). Additionally, a State may trigger a review of an existing facility under § 250.57-2. An affected State may request that the Director supply basic emission data from existing facilities when the data are needed for the updating of the State's emission inventory. In submitting the request, the State must demonstrate that any similar onshore or offshore facilities under the State jurisdiction are included in the State's emission inventory. After the submission of this request by the State, the Director may require lessees of existing facilities to submit the basic emission data to the requesting State. The State then is given the opportunity to submit information to the Director which indicates that emissions from existing facilities may be significantly affecting the air quality of the State.

The Director will evaluate the information submitted by the State and will provide the lessees involved an opportunity to comment on the State's information. The Director will then evaluate all information. If the Director determines that no existing facility has the potential to significantly affect the air quality of the State submitting the information, the Director shall notify the State of this finding and explain the basis for this determination. If the Director determines that a facility has the potential to significantly affect the air quality of the State submitting the information, the Director shall require the lessee of the facility to submit within 120 days, or a longer period of time if the Director determines it is needed, information required to make findings concerning the impacts on onshore air quality impacts.

In submitting such information, the lessee shall apply the same exemption levels and significance criteria as are applicable to new facilities. If, under these criteria, any non-VOC or VOC emission is determined to significantly affect any onshore area, then the lessee is required to reduce the emissions through the application of BACT. The Department does not intend that an existing facility must shutdown if it is determined to significantly affect an onshore area. Instead a compliance schedule for the application of BACT must be submitted to the Director. The Director will monitor the progress of the lessee to insure adherence to the compliance schedule. If it is neccesary to cease operations to allow for the installation of emission controls, the lessee may apply for a suspension of operations under the provisions of 30 CFR 250.12.

Some commenters suggested that, if the Department declined to create an exemption for existing facilities, the BACT requirement should only apply to those facilities affecting nonattainment areas. They recommended eliminating any control requirements when attainment or unclassifiable areas would be impacted. For a discussion of the Department's rejection of this suggestion, see "Prevention of Significant Deterioration."

One commenter argued that the regulations should set out the requirements a State must meet to activate the review process for existing facilities. The final regulations do not set forth a comprehensive list of requirements a State must meet. However, they do require that before a State can request basic emissions data from the Director, it must submit information demonstrating that similar onshore or offshore facilities within the State's jurisdiction also are included in the State's emissions inventory.

Another reviewer suggested that provisions be added which describe the criteria the Director will apply in determining whether existing facilities have the potential to significantly affect an onshore area. The final regulation states that the Director will base this decision on information available on the facilities themselves (i.e. basic emissions data), meteorological data, and the distance of the facility from shore. The Department cannot be more specific about these factors because they will vary from area to area.

Finally, one commenter suggested that the 120-day provision for revision of the plan should be deleted. The requirement has not been deleted, but a provision has been added which allows the Director to extend the 120-day period whenever necessary.

The regulatory procedure described in this final rule for existing facilities is essentially the same as the one in the proposed regulations. The major change involves the States' ability to request the submission of basic emission data. For a more detailed discussion of the comments received on provisions relating to existing facilities, see "Existing Facilities"

OVERVIEW OF THE REGULATORY PROGRAM

The final regulations are designed to insure that emissions from OCS facilities do not cause significant effects on the onshore air quality of a State. The program is divided into three steps for each air pollutant. The first two steps are screening procedures to determine whether emissions of an air pollutant from an

OCS facility would significantly affect the onshore air quality of a State. The third step, if necessary, determines what measures the lessee must take to mitigate the impact of the emissions of the air pollutant. These steps are illustrated in Figure 1.

Step 1: Do the emissions of an air pollutant exceed the exemption amount "E"?

The projected emissions of an air pollutant from each facility are calculated and compared to an emission exemption amount "E". The emission exemption amount "E" is dependent upon the distance of the facility from shore and is calculated for each air pollutant on the basis of formulas described in the regulations. If the projected emissions from the facility are equal to or less then "E", the facility is exempt from further air quality review for that air pollutant and the information required from the lessee is limited to projected emission and distance data and an explanation of how the exemption formulas were applied. (For exploration plans see § 250.34-3(a)(4)(ii)(A), for development and production plans see § 250.34-(3)(b)(4)(ii)(A).

Step 2: Do the emissions of an air pollutant cause onshore air pollutant concentrations to exceed the significance levels established in the regulations?

If a facility is not exempt under Step 1 because the emissions of an air pollutant from the facility exceed the emission exemption amount "E", the lessee must determine whether the emissions cause onshore pollutant concentrations above the "significance levels" established in the regulations.

For non-VOC emissions of TSP, SO_2, NO_2, and CO which exceed the emission exemption amount "E", the lessee must determine the onshore concentrations by air pollutant that will be caused by the offshore emissions. This is done through the application of models approved by GS. The resulting onshore concentration of these pollutants is then compared to the significance levels established in the regulations. If the emissions result in onshore concentrations below the significance level for that pollutant, the facility is not subject to further regulatory review for that pollutant and the information submitted by the lessee need include only the projected emission and distance data, and the information related to the meteorological data and models used. (For exploration plans see § 250.34-3(a)(4)(ii)(A) and (B); for development and production plans see § 250.34-3(b)(4)(ii)(A) and (B).

A VOC emission which exceeds the emission exemption amount "E" is deemed to significantly affect an onshore area of the State.

Step 3: What degree of control is necessary?

Lessees must control the emissions of those air pollutants which are not "screened out" of the regulatory scheme under either Step 1 or Step 2. The degree of control imposed depends on the air quality status of the nearby onshore area and the nature of the pollutant. The control requirements are summarized as follows:

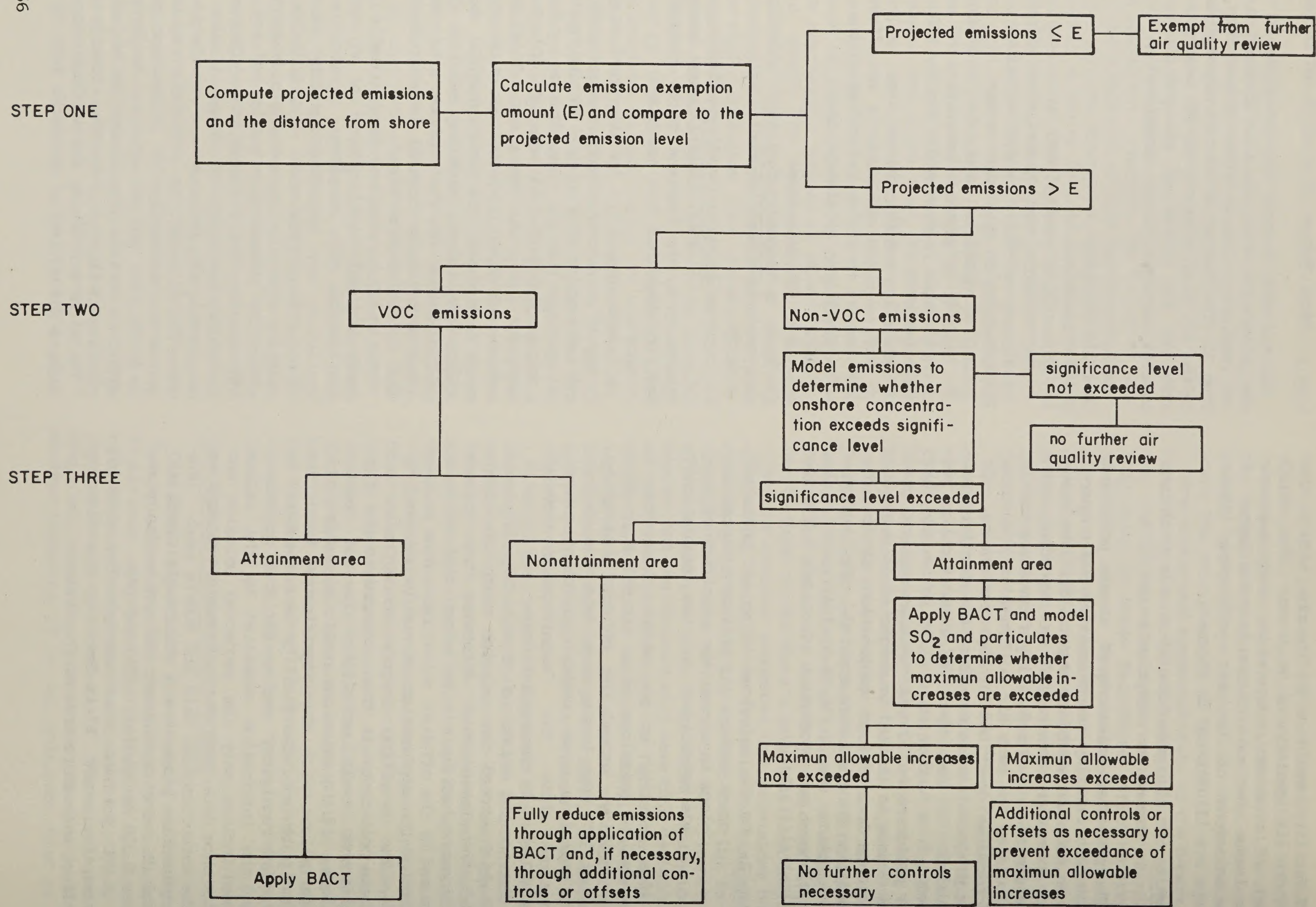
Emission
Controls Required
Non-VOC emissions:
1. Affecting a nonattainment area
BACT + additional controls or offsets necessary to "fully reduce" emissions
2. Affecting an attainment area
BACT + additional controls or offsets necessary to prevent exceedance of maximum allowable increases for SO_2 and TSP.
VOC emissions:
1. Affecting a nonattainment area
BACT + additional controls or offsets necessary to "fully reduce" emissions
2. Affecting an attainment area
BACT
Non-VOC or VOC emissions:
1. From a temporary facility affecting an attainment or a nonattainment area
BACT
2. From an existing facility affecting an attainment or a nonattainment area (except if designated by the Director to be treated as a facility described in a new plan)
BACT

A lessee proposing a facility which is subject to any of these control requirements must submit all information reqired by § 250.34-3(a)(4)(ii)(A) through (D) for exploration plans or § 250.34-3(b)(4)(ii)(A) through (D) for development and production plans. This includes information about projected emission and distance from shore, the meteorological data and models used and the modeling results, the air quality status of the onshore area, and the emission reduction control technologies to be used to reduce emissions.

This regulatory scheme is applicable to any newly proposed facility or to any proposed modification of a facility. It also is to be applied to any existing facility which the Director identifies under § 250.57-1(b) as a facility with the potential to significantly affect the onshore air quality of any State. Additionally, the information requirements and procedures described in Steps 1 and 2 for determining significance are to be followed where the Director, at a State's request, requires the submission of information pursuant to § 250.57-2 for an existing facility. The emissions control requirement for existing facilities is limited to the installation of BACT.

Decisions concerning the potential impacts on onshore air quality of emissions from OCS facil-

FIGURE 1: AIR REGULATORY SCHEME FOR OCS FACILITIES



ities and the necessity for control or offset of those emissions will be made as part of the approval process for exploration plans and development and production plans (see Sections 11 and 25 of the Act). As part of its review of the plan the GS will evaluate the information submitted by the lessee. State and local governments will have an opportunity to review and comment on the information in accordance with the procedures described in 30 CFR 250.34. The exploration plan or development and production plan will not be approved until the GS is satisfied that the air emission data are accurate, that the air models have been run in accordance with relevant guidelines, and that, where applicable, the controls and other mitigating measures proposed are adequate and available.

Because the Survey has integrated the air quality regulations into its established regulatory scheme, no separate permit issuing procedure is necessary. A lessee can undertake no exploratory, development or production activities on a lease until the applicable plan is approved and required drilling permits are granted. Additionally, at any time after approval of a plan the Department has authority to suspend operations under 30 CFR 250.12 if the lessee deviates from the approved plan. If, for instance, a lessee fails to honor a commitment to obtain an offset, or to take some other action to prevent or mitigate the effects of emissions from operations under an approved plan, operations can be suspended until the problem is remedied. The lessee also may be assessed substantial monetary penalties for failure to conduct activities on the OCS in accordance with the approved plan.

ENVIRONMENTAL IMPACT AND REGULATORY ANALYSIS

The Department of the Interior has determined that the revision of the regulations in 30 CFR Part 250, in accordance with this notice, is not a major Federal action significantly affecting the quality of the human environment and will not require preparation of an Environmental Impact Statement. The Department has also determined that this notice of final rule is a significant rule but does not require preparation of a regulatory analysis under Executive Order 12044 and implementing regulations 43 CFR Part 2.

CECIL D. ANDRUS,
Secretary of the Interior

FEBRUARY 29, 1980

4. Preamble, 30 CFR 250.50, 250.51, and 250.52, Unitization; and Pooling, and Drilling Agreements, 45 FR 29280, May 2, 1980.

DEPARTMENT OF THE INTERIOR

Geological Survey

30 CFR Part 250

Oil and Gas and Sulphur Operations in the Outer Continental Shelf

AGENCY: Geological Survey, U.S. Department of the Interior.

ACTION: Final rule.

SUMMARY: This rule incorporates the modifications of §§ 250.50, 250.51, and 250.52 of Chapter II of Title 30 of the Code of Federal Regulations required to implement the Department of the Interior's responsibility to assure prompt and efficient exploration and development of leased areas and to issue regulations "for unitization, pooling, and drilling agreements (43 U.S.C. 1334)." A proposed rule was published on August 10, 1979, in the Federal Register (44 FR 47109). The proposed rule described the modified practices and procedures which were proposed to be used by the Geological Survey in its exercise of the Secretary of the Interior's discretionary authority to approve unitization, pooling, and drilling agreements. Issuance of this rule implements changes that conform to the Department of the Interior's efforts to assure prompt and efficient exploration and development of leased areas.

DATES: This rule becomes effective June 30, 1980.

ADDRESSES: A copy of §§ 250.50, 250.51, and 250.52 of Title 30 of the Code of Federal Regulations may be obtained from the following offices of the Geological Survey:

Deputy Division Chief, Offshore Minerals Regulation, Conservation Division, U. S. Geological Survey, National Center, Mail Stop 640, 12201 Sunrise Valley Drive, Reston, Virginia 22092;

Conservation Manager, Alaska Region, U.S. Geological Survey, 800 "A" Street, Suite 109, Anchorage, Alaska 99501;

Conservation Manager, Pacific OCS Region, U.S. Geological Survey, 1340 West Sixth Street, Room 160, Los Angeles, California 90017;

Conservation Manager, Eastern Region, U.S. Geological Survey, 1725 K Street NW., Suite 204, Washington, D.C. 20244;

Conservation Manager, Gulf of Mexico OCS Region, U.S. Geological Survey, 336 Imperial Office Building, P.O. Box 7944, Metairie, Louisiana 70010.

FOR FURTHER INFORMATION CONTACT:

Gerald D. Rhodes, Senior Staff Assistant, Branch of Marine Oil and Gas Operations, Conservation Division, U.S. Geological Survey, National Center, Mail Stop 640, Reston, Virginia 22092 (703) 860-7531, FTS 928-7531.

SUPPLEMENTARY INFORMATION:

BACKGROUND

In April 1978, the Department of the Interior initiated a review of the past and current criteria and procedures used in the unitization of operations under OCS oil and gas leases. The results of that review led to: (1) The proposed revisions of 30 CFR 250.50 and 250.51 that were published August 10, 1979; and (2) the development of the model unit agreement that was also published in the Federal Register on August 10, 1979 (44 FR 47169). Issuance of this rule completes the revisions to 30 CFR Part 250 which were initiated to implement the requirements of the OCS Lands Act Amendments of 1978.

COMMENTS

Twenty-one sets of comments and recommendations were submitted in response to the invitation contained in the Notice of proposed rule published August 10, 1979. All of the comments and recommendations that were received came from oil and gas companies and trade organizations.

DIFFERENCES BETWEEN PROPOSED RULE AND FINAL RULE

The differences between the provisions of the final rule and the provisions of the proposed rule are the result of the Department's efforts to incorporate the comments and recommendations that were received, to make the provisions of the final rule more clear, and to assure conformance with the OCS Lands Act, as amended, 43 U.S.C. 1331, et seq. (herein referred to as the "Act").

The proposed rules set forth all unitization provisions in § 250.50, and pooling and drilling agreement provisions were set forth in § 250.51. For the final rule, two sections are devoted to unitization, §§ 250.50 and 250.51, and the text of § 250.52, published October 26, 1979, has been deleted in favor of the proposed provisions for § 250.51, "Pooling and drilling

agreements," published August 10, 1979. Definitions have been added to § 250.2 for use with the final rule. The authority and guidelines for unitization are set forth in § 250.50, while the procedures to be followed to accomplish unitization are set out in § 250.51. The model unit agreement will be published as a separate Federal Register Notice at a later date.

SECTION-BY-SECTION ANALYSIS

Definitions have been added to improve clarity and to respond to several commenters' suggestions. Definitions of unit agreement, unit area, unitized substances, unitization, and pooling and drilling agreements have been added to 30 CFR 250.2, where the definitions of other terms relevant to the regulations in this Part are located. To the extent practicable, the definitions being added to § 250.2, "Definitions," are consistent with the definitions of similar terms set forth in 30 CFR Parts 226 and 271.

Section 250.50 Authority and guidelines for unitization.

Subsection 250.50(a) sets forth the basic authority for unitization, which is the conservation of the natural resources of the OCS. The natural resources of the OCS include all natural resources of the OCS, not just mineral resources (see subsection 2(e) of the Submerged Lands Act (43 U.S.C. 1301-1315)). Hence, in addition to being authorized for the purpose of preventing waste of mineral resources, unitization is also authorized to conserve living resources of the OCS and to protect the marine environment.

Generally, unitization will not be authorized solely to protect correlative rights. A lease does not grant lessees the ownership of minerals in place, and the Law of Capture applies to the development and production of OCS minerals. However, where development rights are constrained so that different lessees with separate rights to develop a common resource have unequal development opportunities, and the inequality was not apparent at the time the leases were offered, unitization may be authorized to protect correlative rights. Protection of correlative rights expressly include Federal interests such as royalty interests, which is now of greater importance due to the different types of bidding systems authorized by the Act.

Three different unitization situations are recognized:

(1) Voluntary unitization;

(2) Compulsory unitization initiated by less than all affected lessees; and

(3) Compulsory unitization initiated by the Director.

Subsection 250.50(b) sets forth the basic guideline for unitization. Unitization must be related to a mineral reservoir or potential hydrocarbon deposit and the technical considerations for developing that reservoir or deposit. The purpose for authorizing unitization is to allow the optimal number of artificial islands (or other devices) necessary for efficient exploration, development, and production of a reservoir or potential hydrocarbon deposit. These are the primary technical constraints. Unitization is authorized for the minimum area necessary to accomplish this purpose so that unproductive portions of leases are not unitized.

Development constraints may be imposed by other considerations such as preservation of environmental quality (including water quality, biological resources, and ecosystems) of areas in and above the OCS and in adjacent areas of State jurisdiction. Considerations relating to State coastal zone management programs and air and water quality impacts in areas of State jurisdiction may impose constraints on the development of OCS minerals. Such constraints may place lessees in an unexpectedly unequal position with respect to leased resources subject to correlative rights. These constraints may reduce the number of artificial islands or other devices that can be used, or may limit the locations where such facilities may be constructed. Unitization, either compulsory or voluntary, can provide for the most optimally efficient development of mineral reservoirs and also provides protection for correlative rights in such situations.

Unitization for exploratory purposes is not highly encouraged, but it is expressly authorized. The provisions for the adjustment of the unit area are addressed primarily to exploratory units. After exploration has been completed, a better delineation of the mineral reservoir will be available, and adjustments prior to development and production may be warranted. In keeping with the minimum area standard, the portions of leased areas that do not overlie the more precisely delineated reservoir should be excluded from the unit area in an adjustment. In response to comments, the word "adjustment" is used in lieu of "contraction" to accomodate an expansion if reservoir or field delineation indicates that an enlargement of the unit area is warranted. Approval of development and production plans for the unit area is contingent on acceptance of any adjustments in the unit area required by the Director.

Generally, units will be formed for single reservoirs or structures where potential hydrocarbon accumulations are anticipated. However, exploration may prove the presence of several noncontiguous reservoirs in a single structure or nongeological constraints may require the unitization of an area containing more than

one reservoir or an area containing less than a complete reservoir in order to use the optimum number of platforms or artificial islands. Where unitization is approved for exploration and noncontiguous reservoirs are discovered, the unit area should be adjusted to eliminate nonreservoir areas. Reservoirs need not be eliminated from the unit area even if a noncontiguous unit area results. The provision of the proposed rule which indicated that lessees can reapply for unitization if a reservoir eliminated from a unit area has been deleted as unnecessary. It is not anticipated that a productive reservoir will be eliminated from a unit area.

Subsection 250.50(c) requires the reasonable delineation of a reservoir or of a potential hydrocarbon accumulation before unitization can be approved or required. In the exploration context, delineation can be established by geological and geophysical data that the Director determines is reasonably reliable. For development and production unitization, delineation must be established through the results of exploratory drilling.

Subsection 250.50(d) sets out what a unit agreement must contain. Although a model unit agreement will be published at a later date, variations from the model unit agreement are expected. The requirements of this subsection govern all unit agreements whether they conform to the model unit agreement or not. This subsection also provides that the Director may appoint the unit operator and prescribe a basis on which to allocate costs and benefits in the absence of an agreement on those matters among the lessees. In addition to governing the compulsory unitization situation, these provisions permit the Director to step in to preserve unitization that was initially undertaken on a voluntary basis but which is in danger of dissolution as a result of a disagreement among the lessees.

Subsection 250.50(e) has been written to make it clear that the purpose of unitization is not to continue leases in force beyond their primary term. One of the effects of unitization is that a lease that is subject to a unit agreement may be continued in force by unit operations conducted on the unit in behalf of the lease. However, when there is no drilling, production, or well reworking activities in the unit area, leases expire, as does the unit agreement. Upon the expiration of a unit agreement, leases that were in the unit area also expire unless they are not beyond their primary term, or unless the lessee independently commences drilling or well reworking on the lease within the time frame allowed in 30 CFR 250.35. Subsection 250.50(e) also points up the need to obtain a suspension under 30 CFR 250.12 to avoid the lapse of unitized leases due to a temporary cessation of drilling, production, and workover operations in the unit during a time period that is required for the design, fabrication, or installation of development and production facilities.

Subsection 250.50(f) provides that a unit agreement is to be effective on the date set forth in the agreement. Subsection 250.50(f) also provides that a unit agreement shall terminate when drilling operations, actual production, or well reworking operations are not being carried out. The issuance of a suspension of production for one or more leases that are subject to the unit agreement will also continue those leases in effect. The unit agreement will also continue for the life of the suspension of production when the suspension covers two or more leases.

Subsection 250.50(g) specifically provides for the segregation of unitized leases. This provision is necessary to permit maintenance of the minimum area standard for unitization. OCS leases usually apply to tracts which exceed 5,000 acres. Often, reservoirs cross tract boundaries and include relatively small portions of lease tracts. Whole leases should not be included in a unit area unless they are reasonably thought to entirely overlie a reservoir or group of reservoirs. Rather, only the portion of a lease overlying a delineated reservoir should be unitized, and the remaining portion should be explored and developed separately. This effects a splitting or segregation of a lease into two separate leases under principles long followed for onshore Federal oil and gas leases.

The justification for segregation is more persuasive for OCS leases than for onshore leases. Lease tracts in general are far larger and lease ownership is far less diverse on the OCS. On the OCS, there is one mineral owner and the identity of the surface manager is the same as the mineral owner. The segregation of OCS leases prevents large areas from being tied up in nonproductive leases due to unitization of a small portion of two or more lease tracts. Segregation will encourage prompt and efficient exploration and development because lessees must explore segregated nonunitized portions of leases or relinquish them.

Subsection 250.50(g)(2) spells out that a segregated portion of a lease that is not included in a unit area is treated as a separate lease. It is not continued in force beyond its primary term by operations in the unit area, even if the operations occur on the other segregated portion of the same original base lease. A segregated portion of a lease not included in a unit area must be explored and developed independently of the segregated portion of the lease that is included in the unit area in order to be extended beyond its primary term.

Subsection 250.50(h) provides that at the expiration or termination of a unit agreement each lease lapses unless its initial term has

not expired, or unless drilling, production, or well reworking activities are underway on the lease. This applies to the segregated portions of a lease which are treated as separate leases. Production on the segregated nonunitized portion of the lease will not maintain in force the segregated unitized portion of the segregated lease.

Provisions of other regulations are incorporated. Generally, if drilling, production, or well reworking activities are underway on a lease in a unit area, the unit agreement will remain in force. In the event that a unit agreement is terminated, or where a lease is eliminated from a unit area due to an adjustment, any lease with operations on it would not lapse on termination (see 30 CFR 250.35). With respect to a lease on which operations are not underway at the time of elimination or termination, lease expiration could be avoided by obtaining approval for a suspension of production or other operation under 30 CFR 250.12 in conjunction with a development plan under 30 CFR 250.34.

Subsection 250.50(i) makes it clear that unitization will not continue a lease in force beyond its primary term unless there are actual activities being conducted under the unit agreement that earn a continuance. This is of primary importance for exploratory units. This section encourages prompt and efficient exploration and development of a unit area after approval of a unit agreement.

Subsection 250.50(j) is a grandfather clause designed to protect lessees whose leases were unitized prior to the publication of these regulations. Specifically, it is designed to prohibit retroactive application of the segregation provisions of these regulations to a preexisting lease that is partly within and partly outside a unit area when there is actual production from any part of that lease. Of course, if a lessee consents to the retroactive application through voluntary unitization, the segregation provisions of those regulations can be applied to leases in effect on June 2, 1980. This section cannot be construed, however, as preventing the Director from requiring that a lessee drill or develop specific portions of a lease under other provisions of the regulations in this Part or under provisions of the lease.

Subsection 250.51-1(a) describes the procedures for accomplishing voluntary unitization. It requires that lessees follow the model unit agreement, unless the Director approves a variation at or before the approval of unitization.

Subsection 250.51-1(b) requires the lessee who seeks approval of voluntary unitization to provide supporting information that shows that approval would comply with § 250.50. The fact that lessees can agree on unitization is not in and of itself enough, and the criteria in § 250.50 must still be met. The Director may approve an application for voluntary unitization without a hearing.

Subsection 250.51-2(a) spells out the fact that compulsory unitization can be initiated in two ways, either by one or more lessees who seek to couple the unitization of nonconsenting lessees with correlative rights to a common reservoir, or by the Director for reasons set out in § 250.50. In either event, unitization must be in accordance with a unit agreement whether the unit agreement reflects an actual agreement among some or all of the lessees, or whether it represents a plan developed or approved by the Director. The unit agreement should follow the model unit agreement, and where practicable should reflect any agreement reached between all the lessees, although variation from these principles is authorized for good cause.

Under § 250.51-2(b), compulsory unitization, like voluntary unitization, must conform to the criteria of § 250.50. Supporting information is required. When lessees seek compulsory unitization, they should reach agreement on as many issues as possible between as many lessees as possible before filing a request. Copies of the request must be served on nonconsenting lessees by the lessees requesting unitization. In those instances where the Director initiates unitization, he must notify all affected lessees.

Subsection 250.51-2(c) incorporates provisions which assure a lessee the opportunity for a hearing prior to the issuance of a compulsory unitization order. If no hearing is requested, compulsory unitization may be ordered without a hearing. If a hearing is requested, it shall be held after at least 30 days notice to all lessees of leases to be unitized. Any such hearing shall be informal in nature, but must, as a minimum, provide an opportunity for owners of interests to present information and to question lessees requesting unitization. The words "evidence," "witnesses," and "cross examination" have intentionally been avoided to stress the informal nature of such a hearing. A record shall be compiled by the Dirctor, and any participant may arrange for the proceedings to be transcribed. When proceedings are transcribed, three copies of the transcript are to be provided to the Director within 10 days following the hearing.

Under § 250.51-2(d), the Director's decision on unitization, whether voluntary or compulsory, shall be in the form of a written order and shall include a statement of reasons. An order to accomplish compulsory unitization shall be subject to the appeal provisions of 30 CFR Part 290.

This provision of the final rule and § 250.51(c) constitute the Department's response to the petition for rulemaking dated June 8, 1978, filed by Exxon Corporation.

Section 250.52 has been modified by deleting

the text of the regulations in § 250.52 as published October 26, 1979, and substituting the text of § 250.51 as published August 10, 1979. Pooling and drilling agreements are authorized by this section. They must be filed with the Director, but they need not be approved by him. Such agreements may not excuse a lessee from any of the requirements of the regulations in Part 250. These agreements are distinguished from unit agreements in that they do not create a unit area or affect the terms of the leases concerned, and they are not limited by the criteria for unit agreements.

DISCUSSION OF MAJOR COMMENTS

Extend Comment Period and Hold Informal Meeting. A number of respondents suggested that the comment period for the proposed regulation be extended and that informal meetings be held to afford industry representatives and other representatives an opportunity to participate in a free exchange of views with representatives of the Department of the Interior. Any person interested in an opportunity to participate in a discussion of the proposed regulations with representatives of the Department of the Interior was free to make a specific request for such a meeting during the comment period set out in the Federal Register Notice of August 10, 1979. The Offshore Operators Committee requested and obtained such a meeting in order to present its comments and recommendations on the proposed rule. This meeting was held in Reston, Virginia, on October 5, 1979, and was attended by representatives of the Department of the Interior, the Offshore Operators Committee, Mobil, Gulf, Shell, Exxon, Texaco, and Chevron. In addition, we note that in response to a specific request from the Western Oil and Gas Association, the comment period was extended from October 9, 1979, to November 5, 1979 (44 FR 60109).

Develop Separate Regulations for the Three Major Categories Under Which the Unitization of Operations may be Classified. A number of respondents suggested that the proposed regulations be restructured to more clearly address three different types of unitization:

(a) Unitization of operations initiated and agreed to by all lessees and approved by the Director;

(b) Unitization of operations by order of the Director where the action is on the Director's initiative; and

(c) Unitization of operations ordered by the Director at the request of one or more (but less than all) lessees.

This suggestion has been adopted. The provisions of proposed § 250.50 have been reorganized into new §§ 250.50 and 250.51. Section 250.50, "Authority and requirements for unitization," contains conditions to be met before the unitization of operations will be permitted or required. It distinguishes between voluntary unitization ((a) above) and compulsory unitization ((b) and (c) above), although the conditions for each are similar. Section 250.51, "Procedures for unitization," sets out the different procedures to be followed and requirements to be met in all three situations.

Identify the Nature of the Area Unitized. A number of respondents questioned whether the proposed rule envisioned a unit area to be 2-dimensional or 3-dimensional in nature and suggested that the final rule should clarify the nature of a unit area. The proposed rule and this final rule are designed to permit the unit area to be viewed as either 2-dimensional or 3-dimensional in nature. The nature of the specific unit area addressed in a specific unit agreement will be settled during the time that the unit agreement is being developed. In the event there should be a disagreement over the nature of a specific unit area, the approving officer may determine whether the unit area is for a limited depth. The unit agreement contains a description of the unit area which will define whether the unit area is limited by depth.

Provide for Unitized Operation of Less than an Entire Reservoir. One respondent recommended that the proposed rule be clarified to permit unitized operation of a portion of a reservoir. Generally, unitization should encompass an entire reservoir, or for exploration purposes, a geological structure expected to evidence the possible presence of a potential hydrocarbon accumulation. However, there may be unusual situations, for example, near a Federal/State boundary, near a marine sanctuary, or near some natural feature where unitization of a portion of a reservoir or potential hydrocarbon accumulation would be appropriate. Accordingly, this suggestion has been adopted.

However, it should be noted that it is not the Department's intent to authorize or to require that an area be developed and produced under a unit agreement when the objectives that would be obtained through unitization are being or can be obtained without a unit agreement. Similarly, where the objectives that would be obtained through unitization of an entire structure or reservoir are obtainable through unitization of a portion of the structure or reservoir, unitization may be limited to that portion of the structure or reservoir where unitization is necessary to obtain the desired objectives.

Unitization for Exploration as Well as for Development and Production. A number of commenters expressed concern that the proposed rule did not appear to specifically recognize the need to conduct exploratory operations under a unit agreement. The proposed rule was designed to specifically recognize that there

may be instances where unitized exploration of geologic structures that may provide trapping mechanics for potential hydrocarbon accumulations may be appropriate (see §§ 250.50(f) and (g) of the proposed rule). Use of the term "potential hydrocarbon accumulation" was specifically intended to authorize unitization for exploration by covering the situations where the existence of a potential hydrocarbon bearing geologic structure has been reasonably delineated on the basis of reliable geophysical data, but the existence of a reservoir has yet to be proved. Hence, both the proposed rule and final rule recognize that there may be circumstances which support the conduct of exploration activities under a unit agreement.

Where an area is unitized to conduct exploratory activities, there must be a reasonable expectation that those exploratory activities will be sufficiently complete to permit the unit operator to submit a development and production plan to develop and produce hydrocarbons from the unit area prior to the expiration of the primary 5-year term of any lease that is made subject to the unit agreement. A lease which is subject to an approved unit agreement may expire when it reaches the end of its primary term, in the absence of approved drilling activities, actual production, or a suspension of operations or production pursuant to § 250.12 for the unit area. The Department has consistently maintained that the commitment of an OCS oil and gas lease to a unit agreement in and of itself does not serve to earn an extension of an OCS oil and gas lease. Lease extensions must be earned by actual production, drilling, or well reworking operations in the unit area pursuant to a plan approved in accordance with 30 CFR 250.34.

Unitization of Operations Ordered by the Director at the Request of One or More (but less than all) Lessees. A number of respondents expressed concern that the proposed rule did not appear to establish procedures under which lessees might initiate a request that unitized operations be ordered by the Director. As described in the comments above, the regulations have been revised to clarify the procedures in this situation.

The absence of specific regulations to permit lessees to initiate a request that the Director order unitization has not prevented the initiation of similar requests in the past. At any time during the development of a proposal for voluntary unitization, one or more lessees may request that the Director initiate proceedings which may lead to an order for compulsory unitization. In those instances where the Director, at the request of one or more lessees, initiates proceedings which result in compulsory unitization, essentially the same procedures are to be followed as are followed when the Director initiates such proceedings on his own initiative. In such situations, the unit agreement ordered by the Director may differ from the proposed unit agreement agreed to by the lessee(s) that requested compulsory unitization, but only if the Director makes findings supported by reasons set forth in a statement incorporated in the order requiring unitization.

Maintenance of Lease Acreage by Unit Production. Several respondents expressed concern that implementation of the proposed rule would result in the splitting or segregating of those leases which cover lands that are partly within and partly outside the area that is subject to the unit agreement. That the regulations would authorize segregation of leases is entirely correct, and this is more explicitly stated in the final rule.

The segregation of leases as to lands which are subject to a unit agreement and lands that are not subject to the unit agreement is a well established practice with respect to oil and gas leases issued under the Mineral Leasing Act. The Mineral Leasing Act specifically requires that leases which cover lands that are partly within and partly outside the unit area be segregated (30 U.S.C. 226). With respect to leases covering OCS submerged lands, the Congress gave the Secretary of the Interior broad power to prescribe such rules and regulations as may be necessary to administer the provisions of the Act. The OCS Lands Act of 1953 authorized the Secretary to issue regulations which provide for unitization, pooling, and drilling agreements (43 U.S.C. 1334(a) (1976)). This authority is even more explicitly stated in the 1978 Amendments to the Act (43 U.S.C. 1334(a) (4)). The discretion delegated to the Secretary to adopt regulations governing unitization is extremely broad and clearly authorizes the segregation of OCS oil and gas leases for OCS submerged lands which are partly within and partly outside a unit area.

Many of the commenters who addressed this issue focused on the retroactive application of the segregation provision to existing leases. This is a separate issue from that of the Secretary's authority to adopt regulations providing for the segregation of leases. Persons obtaining leases with knowledge that they are subject to segregation for unitization purposes cannot complain that the regulations effect a taking of property rights. With respect to leases that are now partially unitized and which have production from the unitized portion of the lease, retroactive application of the segregation provisions of these regulations could give rise to a claim that property rights have been "taken." Although the Secretary has adequate authority to accomplish the purposes of segregation by requiring drilling on a specific portion of any lease, the segregation provisions are made nonretroactive absent the consent of the affected lessees. Thus, existing contrac-

tual relations under currently approved unit agreements are not affected by the provisions.

Authority to Promulgate Proposed Rules. A number of respondents questioned the Secretary's authority to issue the proposed rule because it was viewed as relating to diligence, a responsibility which has been assigned to the Department of Energy under section 302 of the Department of Energy Organization Act. The Department is confident that the proposed rule and this final rule are within the authority of the Secretary of the Interior to prescribe rules and regulations necessary to administer the provisions of the Act. Under the 1978 Amendments to the OCS Lands Act, adopted after the Department of Energy Organization Act, the Secretary is required to assure by regulation the "prompt and efficient exploration and development of a lease area" (see 43 U.S.C. 1332(3), 1334(a)(7)). These sections and the previously cited authority for unitization regulations provide the requisite authority. These regulations are not incompatible with the authority of the Department of Energy.

Selection of Unit Operator. Several respondents expressed concern that the proposed rule and proposed model unit agreement dealt with the selection of the unit operator. Some respondents characterize the service as unit operator as a privilege, while others characterized it as a private affair to be handled exclusively by the lessees. The Department has no intention of interfering unnecessarily in the selection of unit operators. On the other hand, the Department will not permit differences over who should be unit operator to jeopardize a necessary unit operation. To this end, the Department has adopted the suggestion that the final rule empower the Director to assign the responsibility for the conduct of unit operations. We find this option preferable to being forced to terminate a unit agreement where the lessees are unable to reach an agreement on who should be the successor unit operator. We reject the contention that the resignation and selection of a unit operator should be governed exclusively by provisions of the unit operating agreement and by agreement of the lessees. The authority to order that lease operations be conducted under a unit agreement carries with it the authority to order a lessee to serve as unit operator. Similarly, the right to hold a lease which may be ordered to be unitized carries with it the responsibility to serve as unit operator under a unit agreement ordered by the Director.

Definitions. A number of respondents suggested that the final rule should define certain terms which the commenters considered basic. These suggestions have been adopted to the extent that § 250.2, "Definitions," has been expanded to include definitions of "unitization," "unit area," "unit agreement," "unitized substances," and "pooling or drilling agreements." These definitions are similar to the definitions found in 30 CFR Parts 226 and 271. The suggestions that "prevention of waste," "protection of correlative rights," and "conservation of natural resources" be defined have not been adopted because they have settled meanings in the law relating to mineral leases in general, and OCS mineral leases in particular. Some terms including "correlative rights," "lessee," and "lease," are already defined in 30 CFR 250.2. Suggestions for other definitions have not been adopted because the terms are not used in the regulations.

Several commenters objected to the use of the term "Federal royalty interests" in § 250.50(a) on the grounds it is included in the term "correlative rights." The current definition of "correlative rights" in 30 CFR 250.2 specifically relates to relationships between lessees and does not include Federal royalty interests. Therefore, the reference to Federal royalty interests is retained in the final rule.

Application of Rule to Pending Proposals. A number of respondents suggested that the requirements of the proposed rule should not be applicable to those unitization proposals that may be pending before the Department of the Interior. This suggestion has not been adopted. To the extent that this rule reflects the Secretary's policy on prompt and efficient exploration and development of OCS oil and gas leases and unit areas, the requirements of this final rule are presently being applied to unit proposals and have been applied to such proposals for a number of months. However, the final rule does set forth those instances where specific provisions of the final rule are not applicable to leases which were issued and unitized prior to the publication of the final rule, e.g., the compulsory segregation of leases issued and unitized prior to the publication of this final rule.

Delete § 250.52. The suggestion to delete the text of § 250.52 as published October 26, 1979, has been adopted and the provisions of proposed § 250.51 which were published August 10, 1979, have been substituted as a new § 250.52. The provisions that were published as a proposed rule on August 10, 1979, and identified as § 250.50 have been reorganized and clarified. This reorganization results in a separation of the provisions into two new sections, §§ 250.50 and 250.51, as explained in greater detail above.

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ENVIRONMENTAL IMPACT AND REGULATORY ANALYSIS STATEMENTS

The Department of the Interior has determined that the revisions of the regulations in 30 CFR 250.50, 250.51, and 250.52, by the issuance of this rule, will not have a significant impact on the quality of the human environment and, therefore, will not require preparation of an Environmental Impact Statement. The Department has also determined this rule is not a significant rule and does not require preparation of a regulatory analysis under Executive Order 12044 and 43 CFR Part 14.

JOAN M. DAVENPORT,
Assistant Secretary

APRIL 29, 1980

5. Regulations, 30 CFR 250, Oil and Gas Sulphur Operations in the Outer Continental Shelf, Title 30 CFR, revised as of July 1, 1979, amended by: 44 FR 53693, September 14, 1979; 44 FR 61892, October 26, 1979; 45 FR 15142-43-44, March 7, 1980; 45 FR 20464-65, March 28, 1980; 45 FR 29285, May 2, 1980; 45 FR 37816-18, June 5, 1980; 45 FR 74471, November 10, 1980; and 45 FR 81563, December 11, 1980.

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AUTHORITY: Outer Continental Shelf Lands Act 43 U.S.C. § 1331 et seq., as amended, 92 Stat. 629; National Environmental Policy Act of 1969, 42 U.S.C. § 4332 et seq. (1970); Coastal Zone Management Act of 1972, as amended, 16 U.S.C. § 1451 et seq.

CROSS REFERENCE: For other regulations pertaining to the issuance and recognition of mineral leases covering submerged lands in the Outer Continental Shelf, see 43 CFR Part 3300.

GENERAL PROVISIONS

§ 250.1 Purpose and authority.

The Act authorizes the Secretary to prescribe rules and regulations necessary to carry out the provisions of the Act. The Secretary is authorized to prescribe and amend regulations that the Secretary determines to be necessary and proper in order to provide for the prevention of waste and the conservation of the natural resources of the Outer Continental Shelf (OCS) and the protection of correlative rights therein, and these rules and regulations apply as of their effective date to all operations conducted under a lease issued or maintained under the provisions of the Act. In the enforcement of safety, environmental, and conservation laws and regulations, the Secretary is authorized to cooperate with other relevant Departments and Agencies of the Federal Government and of affected States. Subject to the supervisory authority of the Secretary, and unless otherwise specified, the regulations in this Part shall be administered by the Director of the Geological Survey.

[34 FR 13544, Aug. 22, 1969; and 44 FR 61892, Oct. 26, 1979]

§ 250.2 Definitions.

When used in the regulations in this Part, the following terms shall have the meanings given below:

(a) "Act" means the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 et seq.).

(b) "Affected local government" means the principal governing body of a locality which is in an affected State and is identified by the Governor of that State as a locality which will be significantly affected by oil and gas activities on the OCS.

(c) "Affected State" means, with respect to any program, plan, lease sale, or other activity proposed, conducted or approved pursuant to the provisions of the Act any State:

(1) The laws of which are declared, pursuant to section 4(a)(2)(A) of the Act, to be the law of the United States for the portion of the OCS on which such activity is or is proposed to be conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or installation or other device permanently or temporarily attached to the seabed.

(3) Which is receiving or, in accordance with the proposed activity, will receive oil for processing, refining, or transshipment which was extracted from the OCS and transported directly to such State by means of vessels or by a combination of means including vessels:

(4) Which is designated by the Secretary as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment or a State in which there will be significant changes in the social, governmental, or economic infrastructure resulting from the exploration, development, and production of oil and gas anywhere in the OCS; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oilspill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

(d) "Analyzed geological information" means data collected under a permit or a lease which have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analyses, laboratory analyses of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

(e) "Area adjacent to a State" means that portion of the OCS which would be within the area of a State if the State's boundaries were extended seaward to the outer margin of the OCS.

(f) "Coastal environment" means the physical atmospheric and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone.

(g) "Coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal States. The coastal zone includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches. The coastal zone extends seaward to the outer limit of the United States territorial sea and extends inland from the shoreline to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States, pursuant to the authority of section 305(b)(1) of the Coastal Zone Management Act.

(h) "Coastal Zone Management Act" means the Coastal Zone Management Act of 1972, as amended (16 U.S.C. § 1451 et seq.).

(i) "Correlative rights," when used with respect to lessees of adjacent tracts, means the right of each lessee to be afforded an equal opportunity to explore for, develop, and produce, without waste, oil or gas, or both, from a common source.

(j) "Cultural resource" means a site, struc-

ture, or object of historical or archeological significance.

(k) "Data" means facts and statistics or samples which have not been analyzed or processed.

(l) "Development" means those activities which take place following discovery of minerals in paying quantities including but not limited to geophysical activity, drilling, platform construction, and operation of all directly related onshore support facilities, and which are for the purpose of ultimately producing the minerals discovered.

(m) "Directional drilling" means the deviation of a borehole from the vertical or from its normal course in an intended predetermined direction or course with respect to the points of the compass. Directional drilling shall not include deviations made for the purpose of straightening a hole that has become crooked in a normal course of drilling or deviations made at random, without regard to compass direction, in an attempt to sidetrack a portion of the hole on account of mechanical difficulty in drilling.

(n) "Director" means the Director of the Geological Survey of the U.S. Department of the Interior or a subordinate authorized to act on the Director's behalf.

(o) "Drilling operations" means actual operations including the physical penetration of the seafloor for the purpose of creating a borehole, testing activities to demonstrate the capability of a well to produce oil or gas, and the completion operations needed to make a well physically able to produce oil or gas, or both.

(p) "Eastern Gulf of Mexico" means all OCS areas in the Gulf of Mexico deemed by the Director to be adjacent to the State of Florida.

(q) "Exploration" means the process of searching for minerals. Exploration activities include but are not limited to: (1) Geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of such minerals and (2) any drilling, whether on or off a known geological structure. Exploration also includes the drilling of a well in which a discovery of oil or natural gas in paying quantities is made and the drilling of any additional well, after a discovery, which is needed to delineate a reservoir and to enable the lessee to determine whether to proceed with development and production.

(r) "Fair Market Value" means the value of any mineral computed at a unit price equivalent to the average unit price at which the the mineral was sold pursuant to a lease during the period for which any royalty or net profit share is accrued or reserved to the United States pursuant to the lease. If the Secretary finds that there were no sales or there were an insufficient number of sales to equitably determine the value, computed at the average unit price at which the mineral was sold pursuant to other leases in the same region of the OCS during the period, or if the Secretary finds there were no sales of the mineral from the region during the period or there were an insufficient number of sales to equitably determine the value, fair market value shall be computed at an appropriate price determined by the Secretary.

(s) "Gas" means any fluid, either combustible or noncombustible, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely; a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

(t) "Governor" means the Governor of a State, or the person or entity designated by, or pursuant to, State law to exercise the powers granted to a Governor pursuant to the Act.

(u) "Human environment" means the physical, social, and economic components, conditions, and factors which interactively determine the state, condition, and quality of living conditions, employment, and health of those affected, directly or indirectly, by activities ocurring on the OCS.

(v) "Information," when used without a qualifying adjective, includes analyzed geological information, processed geophysical information, interpreted geological information, and interpreted geophysical information.

(w) "Interpreted geological information" means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of data and analyzed geological information.

(x) "Interpreted geophysical information" means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

(y) "Lease" means any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, minerals, or the area covered by that authorization, whichever is required by the context.

(z) "Lessee" means the party authorized by a lease, or an approved assignment thereof, to explore for and develop and produce the leased deposits in accordance with the regulations in this Part. The term includes all parties holding that authority by or through the lessee.

(aa) "Major Federal Action" means any action or proposal by the Secretary which is subject to the provisions of section 102(2)(C) of the National Environmental Policy Act (i.e., an action which will have a significant impact upon the quality of the human environment requiring preparation of an Environmental Impact Statement pursuant to section 102(2)(C) of the

National Environmental Policy Act).

(bb) "Marine environment" means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the OCS.

(cc) "Minerals" includes oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals which are authorized by an Act of Congress to be produced from public lands and defined in section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1701).

(dd) "National Environmental Policy Act" means the National Environmental Policy Act of 1969 (42 U.S.C. 4332 et seq.).

(ee) "OCS Order" means a formal numbered Order, issued by the Director, that implements the regulations in this Part and specifically applies to operations in an area identified in the Order.

(ff) "Oil" means any fluid hydrocarbon substance other than gas which is extracted in a fluid state from a reservoir and which exists in a fluid state under the existing temperature and pressure conditions of the reservoir. Oil includes liquefiable hydrocarbon substances such as drip gasoline or other natural condensates recovered or recoverable in a liquid state from produced gas.

(gg) "Operator" means the individual, partnership, firm, or corporation having control or management of operations on the leased area or a portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an approved operating agreement.

(hh) "Outer Continental Shelf (OCS)" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(ii) "Party," when used in § 250.80, means the person alleged to have violated any provision of the Act, or any term of a lease, license, or permit issued pursuant to the Act, or any regulation or order issued under the Act, and includes an individual or a public or private corporation, partnership or other association, or a government entity.

(jj) "Permittee" means the party authorized by a permit issued pursuant to Part 251 of this Chapter to conduct activities on the OCS.

(kk) "Processed geophysical information" means data collected under a permit or a lease which have been processed. Processing involves changing the form of data so as to facilitate interpretation. Processing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

(ll) "Pollution contingency plan" means the National Multi-Agency Oil and Hazardous Materials Pollution Contingency Plan or any successor plan thereto.

(mm) "Production" means those activities which take place after the successful completion of any means for the removal of minerals. Production includes removal of minerals, field operations, transfer of minerals to shore, operation monitoring, maintainance, and/or workover drilling, and depends upon the context in which the term is used.

(nn) "Reviewing Officer" means an employee of the Geological Survey who is delegated the authority to assess civil penalties and, when appropriate, to recommend the initiation of criminal proceedings.

(oo) "Secretary" means the Secretary of the Interior or a subordinate authorized to act on the Secretary's behalf.

(pp) "Violation" means a failure to comply with any provision of the Act, or of a regulation or order issued under the act, or any term of a lease, license, or permit issued pursuant to the Act.

(qq) "Waste of oil and gas" means: (1) the physical waste of oil and gas; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of, reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil or gas well or wells in a manner which causes or tends to cause reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; and (4) the inefficient storage of oil.

(rr) "Well reworking operations" means physical activities designed to restore the capability of a well to produce oil or gas, or both, in paying quantities, or to increase the capability of a service well (e.g., an injection well, a water source well, or a disposal well) to perform the needed function. Reworking operations include, but are not limited to, efforts to clean out, recomplete a well in a different formation, and the physical penetration of formations to relocate the borehole of a well to a more advantageous drainage point within the same formation.

(ss) "Western Gulf of Mexico" means all OCS areas of the Gulf of Mexico except those deemed by the Director to be adjacent to the State of Florida.

(tt) "Air pollutant" means any airborne agent or combination of agents for which the Environmental Protection Agency (EPA) has established pursuant to Section 109 of the Clean Air Act, national primary and secondary ambient air qual-

ity standards.

(uu) "Ambient Air" means that portion of the atmosphere, external to buildings, to which the general public has access.

(vv) "Attainment area" means for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) not to exceed any primary or secondary ambient air quality standard, established by EPA in 40 CFR Part 50, for the air pollutant.

(ww) "Best available control technology (BACT)" means an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation, taking into account energy, environmental and economic impacts and other costs. BACT shall be verified on a case-by-case basis by the Director, and may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant.

(xx) "Emission offsets" means emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed exploration plan or development and production plan. The provisions of Part IV, C and D, of "Appendix S" of EPA's Emission Offset Interpretive Ruling (44 FR 3274, January 16, 1979) are applicable when determining offsets.

(yy) "Existing facility" is an OCS facility described in an exploration plan or a development and production plan deemed submitted, under § 250.34-1(a) or § 250.34-2(a), prior to June 2, 1980, except for a facility identified for review by the Director under § 250.57-1(b).

(zz) "Facility" means any installation or device permanently or temporarily attached to the seabed on the OCS which is used for exploration, development, and production activities, and which emits or has the potential to emit any air pollutant from one or more sources. All equipment directly associated with the installation or device shall be considered part of a single facility if the equipment is dependent on, or affects the processes of, the installation or device. During production, multiple installations or devices will be considered to be a single facility if the installations or devices are directly related to the production of oil or gas at a single site. Any vessel used to transfer production from an OCS facility shall be considered part of the facility while physically attached to the facility.

(aaa) "Nonattainment area" means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) to exceed any primary or secondary ambient air quality standard, established by EPA in 40 CFR Part 50, for the air pollutant.

(bbb) "Onshore area of a State" means areas of a State landward of the mean high water mark (mean higher high water mark on the Pacific coast).

(ccc) "Projected emissions" means emissions, either controlled or uncontrolled, from a source or sources.

(ddd) "State Implementation Plan (SIP)" means a plan submitted to and approved by the EPA, pursuant to Section 110 of the Clean Air Act, which provides for the implementation, maintenance, and enforcement of the national primary and secondary ambient air quality standards within a State.

(eee) "Source" means an emission point. Several sources may be included within a single facility.

(fff) "Temporary facility" means activities associated with the construction of platforms on the OCS or with facilities related to exploration for or development of OCS oil and gas resources which are conducted in one location for less than three years.

(ggg) "Volatile organic compound (VOC)" means any organic compound which is emitted to the atmosphere as a vapor. The unreactive compounds specified by EPA in Table I of "Recommended Policy on Control of Volatile Organic Compounds" (42 FR 35314, July 8, 1977), as it may be amended, are exempt from the above definition.

(hhh) "Unit agreement" means an agreement providing for the exploration for and development and production of minerals from OCS submerged lands as a single consolidated entity without regard to separate ownerships and for the allocation of costs and benefits on a basis defined in the agreement.

(iii) "Unit area" means the area described in a unit agreement.

(jjj) "Unitization" means the combining or consolidation of separately owned lease interests for the joint exploration or development of a reservoir or potential hydrocarbon accumulation under the terms of a unit agreement.

(kkk) "Unitized substances" means the minerals produced from OCS submerged lands in accordance with a unit agreement.

(lll) "Pooling or drilling agreement" means an agreement providing for the exploration for and development and production of minerals from OCS submerged lands subject to separately owned mineral leases and under which operations are conducted without allocation of production between leases.

[19 FR 2656, May 8, 1954; 34 FR 13544, Aug. 22, 1969; 38 FR 10001, Apr. 23, 1973; 44 FR 61892, Oct. 26, 1979; 45 FR 15142, Mar. 7, 1980; 45 FR 20464, Mar. 28, 1980; 45 FR 29285, May 2, 1980; 45 FR 37816, June 5, 1980]

§ 250.3 Data and Information to be made available to the public.

(a) Except as provided in (c) of this section or in § 252.7 of this Chapter, geophysical data, processed geophysical information, and interpreted geological and geophysical information, submitted pursuant to the requirements of this Part, shall not be available for public inspection without the consent of the lessee as long as the lease remains in effect, or for a period of 10 years after the date of submission, whichever is less unless the Director determines that earlier release of such information is necessary for the proper development of the field or area.

(b) Except as provided in (c) of this section or in § 252.7 of this Chapter, geological data and analyzed geological information, submitted pursuant to the requirements of this Part, shall not be available for public inspection without the consent of the lessee as long as the lease remains in effect or for a period of 2 years after the date of submission, whichever is less, unless the Director determines that earlier release of such information is necessary for the proper development of the field or area.

(c) Geophysical data, processed geophysical information and interpreted geophysical information collected on a lease with high resolution systems (including but not limited to, bathymetry, side-scan sonar, subbottom profiler and magnetometer) in compliance with stipulations or orders concerning protection of environmental aspects of the lease may be made available to the public 60 days after submittal to the Director. However, unless the lessee can demonstrate to the satisfaction of the Director that release of the information or data would unduly damage the lessee's competitive position, the Director may release the information and data at an earlier time if the Director determines it is needed by affected States to make determinations under § 250.34 of this Part.

[41 FR 25893, June 23, 1976; 44 FR 61892, Oct. 26, 1979]

§ 250.4 Privileged and proprietary data and information to be available to affected States.

(a)(1) At the time of soliciting nominations for the leasing of lands within 3 geographic miles of the seaward boundary of any coastal State, the Director, in coordination with the Director of the Bureau of Land Management and pursuant to the provisions of subsections 252.7 (a)(4) and 252.7(b) of this Chapter and subsections 8(g) and 26(e) of the Act, shall provide the Governor of the State with:

(i) An identification and schedule of the areas and regions proposed to be offered for leasing;

(ii) All information on the geographical, geological, and ecological characteristics of the areas and regions proposed to be offered for leasing;

(iii) An estimate of the oil and gas reserves in the areas proposed for leasing; and

(iv) An identification of any field, geological structure, or trap located within 3 miles of the seaward boundary of the State.

(2) The manner and form in which the information described in paragraph (a)(1) of this section shall be transmitted to the State shall be determined on a case-by-case basis in discussions between the Director, the Director of the Bureau of Land Management, and the Governor of the State.

(b) After the receipt of nominations for any area of the OCS within 3 geographic miles of the seaward boundary of any coastal State and tentative tract selection in accordance with the provisions of 43 CFR Parts 3313 and 3314, the Director shall, in consultation with the Governor of the State or a duly authorized agent of the Governor, determine whether any tracts being given further consideration for leasing may contain one or more oil or gas reservoirs underlying both the OCS and lands subject to the jurisdiction of the State.

(c) Knowledge obtained by a State official who receives information or data under (a) and (b) of this section shall be subject to the requirements and limitations of the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2), the Act, the regulations contained in this Part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), the regulations in 30 CFR Part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf), and the regulations contained in 30 CFR Part 252 (Outer Continental Shelf Oil and Gas Information Program).

[44 FR 61892, Oct. 26, 1979; 45 FR 20464, Mar. 28, 1980]

§ 250.5 Effect of regulations on provisions of section 6 leases.

(a) As provided in subsection 6(b) of the Act, the regulations in this Part supersede the provisions of any lease which is determined to meet the requirements of subsection 6(a) of the Act, to the extent that they cover the same subject matter, with the following exceptions: the provisions of the lease as to area, rentals, and minerals covered; the royalties payable under the lease (subject to the provisions of paragraphs 6(a)(8) and 6(a)(9) of the Act); and the term of the lease (subject to the provisions of paragraph 6(a)(10) of the Act and, as to sulphur, subject to the provisions of paragraph 6(b)(2) of the Act) shall continue in effect

and, in the event of any conflict or inconsistency, shall take precedence over the regulations in this Part.

(b) A lease that meets the requirements of subsection 6(a) of the Act shall also be subject to the mineral leasing regulations applicable to the OCS as well as the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way in the OCS to the extent that those regulations are not contrary to or inconsistent with the provisions of the lease relating to the area covered, the minerals covered, the rentals payable, the royalties payable, and the term of the lease.

[19 FR 2661, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

JURISDICTION AND FUNCTIONS

§ 250.10 Jurisdiction.

(a) Subject to the supervisory authority of the Secretary, drilling and production operations; handling and measurement of production; determination and collection of rental royalty, and net profit shares; and, in general all operations and activities conducted pursuant to a lease by or on behalf of a lessee are subject to the regulations in this Part and are under the jurisdiction of the Director.

(b) In the exercise of that jurisdiction, the Director is authorized and directed to act upon the requests, applications, and notices submitted under the regulations in this Part, and to require compliance with applicable laws, regulations, lease terms, and OCS Orders so that all operations are conducted in a manner which will protect the natural resources of the OCS. The Director may issue OCS Orders to implement the requirements of the regulations in this Part. The Director may issue other orders, either written or oral, to govern lease operations. Oral orders shall be confirmed in writing as promptly as possible. The Director may issue other orders and field rules to govern the development and method of production of a pool, field, or area. Prior to the issuance of OCS Orders and other orders and field rules, the Director may consult with, and receive comments from, lessees, operators, and other interested parties. Before permitting operations on the leased area, the Director may require evidence that a lease is in good standing, that the lessee is authorized to conduct operations, and that an acceptable bond has been filed.

[38 FR 1001, Apr. 23, 1973; 44 FR 61892, Oct. 26, 1979]

§ 250.11 Functions.

(a) The Director, in accordance with the regulations in this Part, shall:

(1) Regulate all operations conducted under a lease or permit and shall issue and amend OCS Orders and other orders and field rules as may be necessary and proper in order to supervise operations and to prevent harm or damage to, or waste of, any natural resource (including any mineral deposits in areas leased or not leased), any life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

(2) Require on all new and, whenever practicable, existing drilling and production operations (including the construction and operation of platforms and pipelines) the use of the best available and safest technologies which the Director determines to be economically feasible, wherever failure of equipment would have a significant affect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

(3) Schedule an onsite inspection, at least once a year, of each facility on the OCS which is subject to any environmental or safety regulations promulgated pursuant to the Act. The inspection shall include all environmental protection equipment and all safety equipment designed to prevent or ameliorate blowouts, fires, spillages, or other major accidents. A lessee shall, on request by the Director, furnish food, quarters, and transportation for Federal representatives to inspect its facilities. Upon request, the lessee will be reimbursed by the United States for the actual costs which it incurs as a result of its providing food, quarters, and transportation for a Federal representative's stay of more than 10 hours.

(4) Conduct periodic onsite inspections without advance notice to the operator of such facility to assure compliance with applicable regulations.

(5) Cooperate with and, when in the Director's judgment it is necessary, consult with or solicit advice from relevant Departments and Agencies of the Federal Government and affected States, executives of affected local governments, and other interested parties.

(6) Identify for those activities under the jurisdiction of the Director those States which are deemed to be affected States as defined in subsection 250.2(c) of this Part.

(b) The Director may prescribe or approve, in writing or orally with subsequent written confirmation, departures from the requirements of OCS Orders and other orders and field rules issued pursuant to paragraph (a)(1) of this section, when such departures are necessary for the proper control of a well, the facilitation of the proper development of a lease, the conservation of natural resources, the protection of life (including fish and other aquatic life) property, or the marine, coastal or human

environment.

[34 FR 13544, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 20464, Mar. 28, 1980]

§ 250.12 Suspension of operations and lease cancellation.

(a)(1)(i) The Director may suspend or temporarily prohibit production or any other operation or activity when the lessee fails to comply with a provision of the Act or any other applicable law, a provision of a lease or permit, a provision of these and other applicable regulations, OCS Orders, or any other written orders or field rules including orders for the filing of reports and well records or logs within the time specified.

(ii) The Director may suspend or temporarily prohibit production or any other operation or activity pursuant to any lease issued or maintained under the Act when the Director determines that there is a threat of serious irreparable, or immediate harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), or to the marine, coastal, or human environment.

(iii) The Director may, pursuant to the provisions of subsections 5(a) and 12(c) and (d) of the Act, suspend or temporarily prohibit production or any other operations or activities when such action is in the interest of national security or defense.

(iv) The Director may suspend or temporarily prohibit productions or any other operation or activity to facilitate the preparation of an environmental impact statement or environmental analysis, or for any other purpose necessary for the implementation of the National Environmental Policy Act.

(2) The Director may suspend or temporarily prohibit production of any other operation or activity separately as to oil or gas, or as to any other mineral designated in the suspension order as to all or any portion of the leasehold.

(3) The Director shall issue orders of suspension or temporary prohibition pursuant to this subsection either in writing or orally with subsequent written confirmation.

(b)(1) Upon the request of a lessee, the Director may suspend or temporarily prohibit production or any other operation or activity pursuant to a lease when the Director determines that the suspension or temporary prohibition is in the national interest and will (i) facilitate proper development of a lease, (ii) allow for the construction of, or for the negotiation for the use of, transportation facilities, or (iii) facilitate the installation of equipment the Director determines is necessary for safety or environmental reasons.

(2) The lessee must submit, with a request for a suspension, the reasons for requesting the suspension, a schedule of work leading to the expeditious initiation or restoration of production or any other operation or activity, and any other information the Director may require.

(3) In determining whether a suspension of production or any other operation or activity is in the national interest, the Director shall consider:

(i) All known significant national benefits and national costs;

(ii) Whether environmental problems or other unforeseen conditions necessitate a significant halt in production or any other operation or activity; and

(iii) Whether, during the primary term, the lessee has been prompt and efficient in the exploration of the lease.

(4) A suspension of production or any other operation or activity may be granted under this subsection for periods of time each of which must not exceed 5 years.

(c)(1) When the Director suspends or temporarily prohibits production or any other operation or activity pursuant to subsections (a) or (b) of this section, the term of the lease shall be extended for a period of time equivalent to the period that the suspension or prohibition is in effect. However, no lease shall be extended pursuant to this subsection when the Director's suspension or temporary prohibition is the result of the lessee's or permittee's gross negligence or of a knowing and willful violation of a provision of the Act, of the regulations, or of a lease or permit.

(2) Any suspension may be terminated at any time when the Director determines that the circumstances which justified the granting of the suspension no longer exist. When the Director terminates a suspension prior to the end of the period of time for which the suspension was originally granted, the Director shall specify in the notice of termination the reason(s) for the termination and the effective date for the termination of the suspension.

(3) Any suspension shall terminate automatically upon the commencement of production or any other suspended operation or activity.

(d)(1) When the Director suspends or temporarily prohibits production or any other operation or activity pursuant to paragraph (a)(1)(ii) of this section, the Director may require the lessee to conduct (a) site-specific study or studies to identify and evaluate the cause(s) of the hazard(s) generating the suspension, the potential damage from the hazard(s), and the measures available for mitigating the hazard(s). The content and scope of the study or studies shall be approved or prescribed by the Director. Prior to approval of a study program, the Director may invite comments and recommendations, on an informal basis, from interested Federal Departments and Agencies,

affected States and local governments, and other interested parties. The lessee shall furnish copies and all results of the study or studies to the Director. The cost of the study or studies shall be borne by the lessee unless the Director arranges for the cost of the study or studies to be borne by a party other than the lessee. The Director shall make such results available to interested parties and to the public.

(2) On the basis of the results of the study or studies conducted in accordance with paragraph (d)(1) of this section and other information available to and identified by the Director, the Director will submit a report to the Secretary. The report shall indicate the damage or threat of damage being avoided and shall recommend mitigating measures. If any, that may successfully alleviate such damage or threat of damage. On the basis of the Director's report and recommendations, and other information or advice the Secretary deems and identifies as relevant, the Secretary shall require the lessee to take appropriate measures to mitigate or avoid the damage or potential damage, which resulted in the suspension or temporary prohibition of production or of any other operation or activity, as a condition to permitting the resumption of exploration, development, or production activities on the lease. The lessee shall submit, when deemed appropriate by the Director, a revised exploration plan or a revised development and production plan in accordance with § 250.34 of this Part. The revised plan shall incorporate the mitigating measures required by the Secretary. In choosing between alternative mitigating measures the Secretary will balance the cost of the required measures against the reduction or potential reduction in damage or threat of damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment.

(3) If the lessee cannot comply with the conditions established by the Secretary for ending the suspension or temporary prohibition of production or any other operation or activity on the lease, or if the Secretary determines that adequate protection from serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine coastal, or human environment will not be provided by the mitigating measures, the Secretary shall leave the suspension in effect.

(4) The Secretary may terminate a suspension and cancel a lease in accordance with the provisions of this subsection when:

(i) Continued activity pursuant to the lease or permit would probably cause serious harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment;

(ii) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(iii) The advantages of cancellation outweigh the advantages of continuing the lease or permit in force.

(5) Cancellation of a lease pursuant to this subsection is in the Secretary's discretion, but cannot occur until the operation or activity in question under the lease or permit has been under suspension or temporary prohibition, with due extension of the term of the lease, continuously for a period of 5 years or, upon the request of the lessee, for a lesser period of time. If a lease is cancelled under this section, the lessee shall be entitled to compensation pursuant to the provisions of subsection (g) of this section.

(6) Cancellation of a lease pursuant to this subsection will become effective only after the affected lessee has been given notice and an opportunity for a hearing.

(e) Whenever an exploration plan is disapproved because the Director determines that approval of the activities called for in the plan would probably cause serious harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment, and the proposed activity cannot be modified to avoid these dangers, the Secretary may, once the primary lease term has been extended continuously or a period of 5 years following the disapproval, or, upon request of the lessee, at an earlier time, terminate the suspension or temporary prohibition and cancel the lease, and the lessee shall be entitled to compensation pursuant to subsection (g) of this section.

(f)(1) Where a development and production plan is submitted before the subsequent approval of a coastal zone management program for an affected State, pursuant to the Coastal Zone Management Act, and the plan is disapproved because the lessee does not receive concurrence by such State pursuant to section 307(c)(3)(B)(i) or (ii) of the Coastal Zone Management Act, and the Secretary of Commerce does not make the finding authorized by section 307(c)(3)(B)(iii) of the Coastal Zone Management Act, or if the Secretary makes findings pursuant to § 250.34-2(g)(2)(iii)(C):

(i) The term of the lease shall be duly extended and at any time within 5 years after such disapproval, the lessee may reapply for approval of the same or a modified plan, and the Director shall approve, disapprove or require modification of the plan in accordance

with the provisions of 30 CFR § 250.34-2; and

(ii) Upon expiration of the 5-year period described in paragraph (f)(1)(i) of this section or at the Secretary's discretion at an earlier time upon request of the lessee, if the Director has not approved a plan, the Secretary shall cancel the lease and the lessee shall be entitled to compensation pursuant to subsection (g) of this section.

(iii) The Secretary may, at any time within the 5-year period described in paragraph (f)(1)(i) of this section, require the lessee to submit a development and production plan for approval, disapproval, or modification. If the lessee fails to submit a required plan expeditiously and in good faith, the Secretary shall find that the lessee has not been prompt and efficient in pursuing obligations under the lease, and, notwithstanding the provisions of subparagraph (f)(1)(i) of this section, the Secretary shall immediately initiate procedures to cancel the lease under the provisions of subsection 5(c) of the Act, and the lessee shall not be entitled to compensation.

(2) Where a development and production plan is submitted after approval of a State's coastal zone management program pursuant to the Coastal Zone Management Act, and the plan is disapproved because the lessee does not receive concurrence by the State pursuant to section 307(c)(3)(B)(i) or (ii) of the Coastal Zone Management Act, and the Secretary of Commerce does not make the finding authorized by section 307(c)(3)(B)(iii) of the Coastal Zone Management Act, the lessee shall not be entitled to compensation when the lease expires.

(3) Whenever the owner of a lease fails to submit a development and production plan in accordance with 30 CFR 250.34-2, or fails to comply with an approved plan, the lease may be cancelled in accordance with sections 5(c) or (d) of the Act. Cancellation of a lease because of failure to submit a plan or to comply with an approved plan, including required modifications or revisions, shall not entitle the lessee to any compensation.

(4) Whenever the owner of a nonproducing lease fails to comply with any of the provisions of the Act, or of the lease, or of the regulations issued under the Act, and the default continues for a period of 30 days after the mailing of a notice by registered letter to the lease owner, the Secretary may cancel the lease pursuant to subsection 5(c) of the Act, and the lessee shall not be entitled to compensation.

(5) Whenever the owner of any producing lease fails to comply with any of the provisions of the Act, of the lease, or of the regulations issued under the Act, the Secretary may cancel the lease pursuant to subsection 5(d) of the Act, and the lessee shall not be entitled to compensation.

(6) Whenever a development and production plan is disapproved because of a failure to demonstrate compliance with the requirements of the Act or other applicable Federal law, including the air quality regulations prescribed by the Secretary pursuant to section 5(a)(8) of the Act, the lessee shall not be entitled to compensation when the lease expires.

(g) Cancellation of a lease under subsections (d), (e) and (f) of this section shall entitle the lessee to receive such compensation as the lessee shows the Director as being equal to the lesser of:

(1) The fair value of the cancelled rights as of the date of cancellation, taking account of both anticipated revenues from the lease and anticipated costs, including costs of compliance with all applicable regulations and operating orders, liability for cleanup costs or damages, or both, in the case of an oilspill, and all other costs reasonably anticipated on the lease; or

(2) The excess, if any, over the lessee's revenues from the lease (plus interest thereon from the date of receipt to date of reimbursement) of all consideration paid for the lease and all direct expenditures made by the lessee after the date of issuance of the lease and in connection with exploration or development, or both, pursuant to the lease (plus interest on this consideration and expenditures from date of payment to date of reimbursement), except that:

(i) With respect to leases issued before enactment of the Act, compensation shall be equal to the amount specified in paragraph (g)(1) of this section; and

(ii) In the case of jointly held leases which are cancelled due to the failure of one or more partners to exercise due diligence, the innocent parties shall have the right to seek damages for losses from the responsible party or parties and the right to acquire the interests of the negligent party or parties and be issued the lease in question.

[34 FR 13544, Aug. 22, 1969; 41 FR 53016, Dec. 3, 1976; 42 FR 53957, Oct. 4, 1977; 44 FR 61892, Oct. 26, 1979; 45 FR 20464, Mar. 28, 1980]

§ 250.13 Temporary approvals.

The Director may give temporary oral approvals whenever the regulations in this Part, other than those contained in § 250.34, require a lessee to obtain the Director's approval before commencing and operation or activity. Oral approvals shall be confirmed immediately in the manner otherwise required by the regulations in this Part.

[19 FR 2656, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.15 Drilling and abandonment of wells.

(a) The Director shall require that drilling and any other operation or activity pursuant to a lease be conducted in accordance with a plan prescribed or approved by the Director in accordance with the regulations in this Part. Whenever practicable, the Director shall require the plugging and abandonment of any well which the Director determines is no longer useful.

(b) Upon failure to secure compliance with the requirements of subsection (a) of this section, the Director may perform the work at the expense of the lessee.

[19 FR 2657, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.16 Well potentials and permissible flow.

The lessee shall produce any oil or gas obtained pursuant to an approved development and production plan, at rates consistent with any applicable rule or order.

[19 FR 2657, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.17 Well spacing.

The Director is authorized to approve well spacing programs necessary for the proper development of a lease giving consideration to, among other factors, the following: the location of drilling platforms; the geological and other reservoir characteristics of the field; the number of wells that can be economically drilled; the protection of correlative rights; and minimizing the unreasonable interference with other uses of the OCS.

[34 FR 13545, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.18 Right of use and easement.

(a)(1) In addition to the rights and privileges granted to a lessee under any lease issued or maintained under the Act, the Director may grant a lessee, subject to conditions prescribed by the Director, a right of use and easement to construct and maintain platforms, artificial islands, and all installations and other devices which are permanently or temporarily attached to the seabed on the OCS, and which are used for carrying out exploration, development, and production activities, including but not limited to drilling, producing, treating, handling, and storing production, and the housing of personnel engaged not only in operations and activities on the lease on which the platform, artificial island, or installation or other device is situated, but for the conduct of operations on any other lease.

(2) A right of use and easement shall be exercised only in a manner which does not interfere unreasonably with operations of any lessee under a lease.

(3) A right of use and easement shall be exercised in a manner which assures protection of the environment through the use of the best available and safest technologies pursuant to subsection 21(b) of the Act.

(4) A right of use and easement, if on an area subject to any lease issued or maintained under the Act, shall be granted only after the holder of the lease has been notified by the applicant and afforded an opportunity to comment on the application.

(b) The Director may approve the design, fabrication, and plan of installation of all platforms, artificial islands, and installations, and other devices permanently or temporarily attached to the seabed on the OCS as a condition of the granting of a right of use and easement under paragraph (a) of this section, or as authorized under any lease issued or maintained under the Act.

(c) Once a right of use and easement has been exercised, the right shall continue, even beyond the termination of any lease on which it may be situated, as long as the Director determines that the right of use and easement is maintained by the holder of the right and serves the purpose specified in the grant. If the grant extends beyond the termination of any lease on which the right of use and easement may be situated, the rights of all subsequent lessees shall be subject to such rights of use and easement.

(d) Upon termination by the Director of a right of use and easement, the grantee shall place in condition, remove, or otherwise dispose of all platforms, artificial islands, and all installations and other devices permanently or temporarily attached to the seabed on the OCS, and pipelines, and restore the premises to the satisfaction of the Director. However, a pipeline or other facility may be abandoned in place as long as the Director determines that it does not constitute a hazard to navigation or commercial fishing. The abandonment of a pipeline or other facility is to be performed in accordance with a plan prescribed or approved by the Director.

[19 FR 2657, May 8, 1954; 34 FR 13545, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 20464, Mar. 28, 1980; 45 FR 77471, Nov. 10, 1980]

§ 250.19 Access to platforms.

The Director is authorized to require that lessees maintaining platforms, artificial islands, and installations and other devices permanently or temporarily attached to the seabed on the OCS which are equipped with helicopter

landing sites and refueling facilities, provide the use of those facilities for helicopters employed by the Department of the Interior in the supervision of operations on the OCS. The lessee shall be reimbursed for costs which the Director determines were justifiably incurred in connection with the use of those facilities by helicopters employed by the Department of the Interior.

[34 FR 13545, Aug. 22, 1969; 39 FR 45015, Dec. 30, 1974; 44 FR 61892, Oct. 26, 1979; 45 FR 20464, Mar. 28, 1980]

§ 250.20 Pipeline approval.

The Director shall approve the design, fabrication, and the plan of installation of OCS pipelines that are wholly contained within the boundaries of a single lease, the boundaries of unitized leases, or the boundaries of contiguous (not cornering) leases of the same owner or operator.

[45 FR 74471, Nov. 10, 1980]

§ 250.21 Reduction of royalty or net profit share.

(a) In order to promote increased production on the lease area through direct secondary, or tertiary recovery means, the Director may reduce or eliminate any royalty or net profit share on the entire leasehold, or on any deposit, tract, or portion thereof that is segregated for royalty purposes.

(b) An application for relief under subsection (a) of this section must contain: the serial number of the lease; the name of the titleholder of record; a description of the area included in the lease; the number, location, and status of each well that has been drilled; and a tabulated statement for each month, covering a period of not less than 6 months prior to the date of filing the application, of the aggregate amount of minerals subject to royalty or net profit share computed in accordance with the lease and applicable regulations. Every application must also contain a detailed statement of: the cost of operating the entire lease, the income from the sale of any products from the lease; and all other facts tending to show whether the wells can be successfully operated under the royalty or net profit share fixed in the lease. Full information shall be furnished as to whether royalties or payments out of production are paid to anyone other than the United States, the amounts paid, and the efforts made to reduce them. The applicant must also file agreements of the holders of the lease and of royalty holders to a reduction of all other royalties from the leasehold to an aggregate not in excess of one half the revised Government royalty or net profit share that would result if the request for a reduction were allowed.

(c) An application for relief under subsection (a) of this section shall be filed in triplicate with the Director.

[44 FR 61892, Oct. 26, 1979; 45 FR 20464, Mar. 28, 1980]

REQUIREMENTS FOR LESSEES

§ 250.30 Lease provisions, regulations, waste, damage, and safety.

(a) The lessee shall comply with the provisions of applicable laws, regulations, the lease, OCS Orders, and other written or oral orders of the Director. All oral orders shall be effective when issued and will be confirmed in writing as promptly as possible.

(b) The lessee shall conduct operations on a lease in a manner that does not, in the opinion of the Director, cause or threaten to cause waste or threaten harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment, and the lessee shall take all necessary precautions to prevent waste, harm, or damage.

(c) The lessee shall use, on all new drilling and production operations and, whenever practicable, on existing operations, the best available and safest technologies that the Director determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, unless the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

[42 FR 53958, Oct. 4, 1977; 44 FR 61892, Oct. 26, 1979; 45 FR 20464, Mar. 28, 1980]

§ 250.31 Designation of operator.

In all cases where operations are not conducted by the owner of record, but are conducted under authority of an unapproved operating agreement, assignment, or other arrangement, a "designation of operator" shall be submitted to the Director, prior to the commencement of operations, in a manner and form approved by the Director. This designation will be accepted as authority for the operator, or the operator's local representative, to act on behalf of the lessee and to fulfill the lessee's obligations under the Act and the regulations in this Part. All changes of address and any termination of the authority of the operator shall be reported immediately, in

writing, to the Director. In case of a termination or in the event of a controversy between the lessee and the designated operator, both the lessee and the operator will be required to protect the interests of the lessor.

[19 FR 2657, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.32 Local agent.

When required by the Director, the lessee shall designate a representative empowered to receive notices and comply with orders of the Director issued pursuant to the regulations in this Part.

[19 FR 2657, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.33 Drilling and producing obligations.

(a) The lessee shall file all plans and drill and produce all wells that the Director may require in order to insure the prompt and efficient exploration for, and development and production of oil and gas from the lease.

(b) The lessee shall drill and produce the wells the Director determines are necessary to protect the lessor from loss by reason of production on other properties, or, with the consent of the Director, shall pay a sum determined by the Director as adequate to compensate the lessor for the lessee's failure to drill and produce any well. Payment of that sum shall be considered as the equivalent of production in paying quantities for the purpose of extending the lease term.

(c) The lessee shall pay the rental and the amount or value of production determined by the Director as accruing to the lessor as royalty or net profit share.

[19 FR 2657, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.34 Exploration, development, and production activities.

§ 250.34-1 Exploration plan.

(a)(1) No exploration activities, except for preliminary activities, may be commenced or conducted on any leased area except in accordance with an exploration plan approved by the Director. For purposes of this section, preliminary activities are geological, geophysical, and other surveys necessary to develop a comprehensive exploration plan. Such preliminary activities are those which do not result in any physical penetration of the seabed of greater than 300 feet of unconsolidated formations, or 50 feet of consolidated formations, and which do not result in any significant adverse impact on the natural resources of the Outer Continental Shelf (OCS). A proposed exploration plan may apply to one or more leases held by an individual lessee, or may be submitted by a group of lessees acting under an approved unitization, pooling, or drilling agreement. An exploration plan shall be based upon all available relevant information and shall identify, to the maximum extent possible, all the potential hydrocarbon accumulations and wells that the lessee(s) propose(s) to drill to evaluate the accumulations in the entire area included within the lease(s) covered by the exploration plan. An exploration plan shall include:

(i) The proposed type and sequence of exploration activities to be undertaken together with a tentative timetable for their performance from commencement to completion;

(ii) A description of any drilling vessel, platform or other installation or device to be permanently or temporarily attached to the seabed indicating the important features thereof with special attention to safety features and pollution-prevention and control features including oil spill containment and cleanup plans;

(iii) The types of geophysical equipment to be utilized;

(iv) The approximate location of each proposed exploratory well, including surface and projected bottom hole locations;

(v) Current structure maps and, as appropriate, schematic cross sections showing expected depths of marker formations; and

(vi) Such other relevant information and data as the Director may require.

(2)(i) Except as provided in paragraph (a)(2)(ii) of this section, at the same time as a lessee submits an exploration plan, an Environmental Report (Exploration) shall be submitted pursuant to the provisions of § 250.34-3(a). The report will not be considered part of the exploration plan; however, the report shall accompany the plan through all review processes.

(ii) A lessee submitting an exploration plan for leases in the western Gulf of Mexico is not required to submit an Environmental Report, unless the proposed exploration activities would affect a land use or water use in the coastal zone of a State with a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act. Also, the Director may request specific environmental information to make the findings required under applicable law, including but not limited to the Act and the National Environmental Policy Act.

(3) For leases issued with an initial period of five years, prior to the end of the second lease year, the lessee shall submit either an exploration plan or a general statement of exploration intentions. For leases issued with an initial period of more than five years, the

lessee shall submit either an exploration plan or a general statement of exploration intentions within a period of time specified at the time the tracts are offered for leasing. When a general statement of exploration intentions is submitted in lieu of an exploration plan, the statement shall be prepared and submitted in a manner and form prescribed by the Director. These requirements shall apply only to leases issued after the effective date of this regulation.

(4) The Director may require that an exploration plan be accompanied by a general statement of development and production intentions. The general statement of development and production intentions shall be prepared and submitted in a manner and form prescribed by the Director and the statement shall be for planning purposes only and shall not be binding on any party.

(5) The lessee shall indicate which portions of the exploration plan the lessee believes are exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2). The lessee shall include a written discussion in the plan of the general subject matter of the deleted portions for transmittal to the recipients of copies of a plan identified in paragraph 250.34-1(b)(1).

(6) An exploration plan shall not be deemed submitted until:

(i) The Director has determined that the plan and accompanying Environmental Report are complete and contain the information required by §§ 250.34-1(a) and 250.34-3(a). The determination of whether a plan and accompanying Environmental Report are complete shall be made within 10 working days after the filing of the plan.

(ii) The plan is accompanied by a certificate of coastal zone consistency as provided in 15 CFR Part 930, whenever the activities described would significantly affect any land use or water use in the coastal zone of any State with a coastal zone management program, approved pursuant to section 306 of the Coastal Zone Management Act.

(iii) The Director has been given the number of copies of a complete exploration plan and accompanying Environmental Report that the Director has determined is necessary for distribution pursuant to § 250.34-1(b)(1). The Director shall advise the lessee of the number of copies that are needed for distribution.

(b)(1) Within 2 working days after the date an exploration plan has been deemed submitted, the Director shall transmit a copy of the plan, except for those portions determined to be exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2), and the accompanying Environmental Report to the Governor of each affected State, except as provided in paragraph (b)(2) of this section, and the coastal zone management agency of each affected State that has a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act. The Director shall also make copies of the exploration plan and accompanying Environmental Report available to any appropriate federal agency, interstate regional entity, and the public in accordance with established Departmental practices and procedures.

(2) The Governor of an affected State adjacent to the western Gulf of Mexico that does not have a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act may receive copies of exploration plans by submitting to the Director a written request for the documents. The Director shall notify the appropriate lessees immediately upon receipt of such a request.

(3) When it is determined that the activities proposed in an exploration plan will affect any land use or water use in the coastal zone of a State with a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act, the plan will be processed in accordance with the regulations in this section and the regulations governing Federal Coastal Zone Management Consistency Procedures (15 CFR Part 930).

(c) The Director shall review the environmental impacts of the activities described in the exploration plan pursuant to the provisions of § 250.34-4.

(d) In the evaluation of an exploration plan, the Director shall consider timely received written comments from the Governor of an affected State, whether or not the State has a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act. The Director may consult directly with affected States regarding matters contained in the comments.

(e)(1) In the evaluation of an exploration plan, the Director shall consider whether the plan is consistent with:

(i) The provisions of the lease;

(ii) The provisions of the Act; and

(iii) The provisions of the regulations prescribed under the Act, including air quality regulations prescribed by the Secretary pursuant to section 5(a)(8) of the Act and environmental, safety, and health requirements.

(2) Within 30 days of submission of a proposed exploration plan, the Director shall:

(i) Approve any plan which is consistent with the criteria in subparagraphs (e)(1) (i), (ii) and (iii) of this section;

(ii) Require the lessee to modify any plan which is inconsistent with paragraphs (e)(1) (i), (ii), or (iii); or

(iii) Disapprove any plan if it is determined that a proposed activity under the plan would probably cause serious harm or damage to life (including fish and other aquatic life), to

property, to natural resources of the OCS including any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment and that the proposed activity cannot be modified to avoid the condition(s).

(3) The Director shall notify the lessee in writing of the reason(s) for disapproving an exploration plan or for requiring modification of a plan and the conditions that must be met for plan approval.

(f) The lessee may resubmit an exploration plan, as modified, to the Director. Within 30 days of resubmission, the Director shall approve or disapprove the modified plan based upon the criteria in paragraphs (e)(1) (i), (ii), and (iii) of this section.

(g) When a State objects to a lessee's coastal zone consistency certification, the lessee shall modify the plan to accommodate the State's objection(s) and resubmit the plan to: (1) the Director for review pursuant to the criteria in paragraphs (e)(1) (i), (ii), and (iii) of this section; and (2) through the Director, to the State for review pursuant to the Coastal Zone Management Act and the implementing regulations (15 CFR 930.83 and 930.84). Alternatively, the lessee may appeal the State's objection to the Secretary of Commerce pursuant to the procedures described in section 307 of the Coastal Zone Management Act and the implementing regulations (Subpart H of 15 CFR 930). The Director shall approve or disapprove a plan as resubmitted within 30 days of the resubmission date.

(h) A modified exploration plan which has been disapproved pursuant to subsection (f) of this section may be revised and resubmitted to the Director for review and approval or disapproval in the same manner as, and with the same information required for, a new plan.

(i) If the Director disapproves an exploration plan, pursuant to paragraph (e)(2)(iii) of this section, the Secretary may, subject to the provisions of section 5(a)(2)(B) of the Act and the implementing regulations (30 CFR 250.12 and 43 CFR 3320.2), cancel the lease(s), and the lessee shall be entitled to compensation in accordance with section (5)(a) of the Act and the implementing regulations (30 CFR 250.12 and 43 CFR 3320.2).

(j)(1) The Director shall periodically review the activities being conducted under an approved exploration plan. The frequency and extent of the Director's review shall be based upon the significance of any changes in available information and in other onshore or offshore conditions affecting or affected by exploration activities being conducted pursuant to the plan. If the review indicates that the plan should be revised to meet the requirements of this Part, the Director shall require such revision pursuant to paragraph (j)(2) of this section.

(2) Proposals to revise an approved exploration plan, whether initiated by the lessee or ordered by the Director, shall be submitted to the Director for approval in the same manner as, and with the same information required for a new exploration plan. When the Director determines that a proposed revision could result in a significant change in the impacts previously identified and evaluated, the revision shall be subject to all of the procedures in this section except those pertaining to the consistency requirements of the Coastal Zone Management Act. When the Director determines that a proposed revision calls for additional permits, the proposed revision shall be subject to all of the procedures in this section. Information copies of all revisions to an approved exploration plan will be forwarded by the Director to the recipients of the previously approved plan.

(k) In order to ensure that activities to be carried out under a proposed exploration plan and activities being carried out under an approved exploration plan are carried out in a safe and environmentally acceptable manner, the Director may authorize or direct the lessee to conduct geological, geophysical, or other surveys that the Director determines are necessary for the evaluation of such activities. The lessee shall provide the Director, upon request and without cost to the lessor, copies of any data obtained as a result of those surveys.

(l) The lessee may not drill any well until the Director's approval of an application for permit to drill, filed in accordance with the requirements of 30 CFR 250.41(a), has been received. The Director shall not approve any permit until all affected States with approved coastal zone management programs have concurred or have been conclusively presumed to concur with the applicant's coastal zone consistency certification accompanying a plan; or the Secretary of Commerce has made the finding authorized by section 307(c)(3)(B)(iii) of the Coastal Zone Management Act. Permit applications must conform to the activities described in detail in the related approved exploration plan and shall not be subject to a separate State coastal zone consistency review.

(m) Nothing in this section shall be viewed as limiting the lessee's responsibility to take appropriate measures to meet emergency situations. In such situations, the Director may approve or require departures from an approved exploration plan.

[43 FR 3883, Jan. 27, 1978; 44 FR 53693, Sept. 14, 1979; 45 FR 20464, Mar. 28, 1980]

§ 250.34-2 Development and production plan.

(a)(1) No development or production activities may be commenced or conducted on any leased area, except in accordance with a

development and production plan approved by the Director. A plan may apply to one or more leases held by an individual lessee or may be submitted by a group of lessees acting under an approved unitization, pooling, or drilling agreement. A plan shall provide for the effective and efficient development and production of all known accumulations of hydrocarbons found on the leasehold(s) that are capable of production in paying quantities. A development and production plan shall include:

(i) A description of the specific work to be performed, including all the development and production activities that the lessee(s) propose(s) to undertake during the time period covered by the plan and all activities to be undertaken up to and including the commencement of sustained production.

(ii) A description of any drilling vessels, platforms, pipelines, or other facilities and operations located on the OCS which are proposed or known by the lessee (whether or not owned or operated by the lessee) to be directly related to the proposed development, including the location, size, design, and important features of the facilities and operations (with special attention to safety and pollution-prevention and control features including oil spill containment and cleanup plans) and the labor, material, and energy requirements associated with the facilities and operations;

(iii) The location of each well, including the surface and projected bottom hole locations;

(iv) Current interpretations of all available relevant geological and geophysical data, including structure maps and schematic cross sections of productive formations;

(v) A description of the environmental safeguards to be implemented in the course of development and production operations under the plan, together with a discussion of how such safeguards are to be implemented;

(vi) All safety standards to be met and the safety features to be utilized in order to meet those standards;

(vii) An expected rate of development and production and a time schedule for the performance of activities from commencement to completion of both; and

(viii) Such other relevant information and data as the Director may require.

(2) For leases in the western Gulf of Mexico the Director may limit the information that will be required to be included in a development and production plan to those parts of paragraphs (a)(1) (i) through (viii) that are necessary to assure conformance with the Act, other laws, applicable regulations, and lease provisions. In determining the information to be included in a plan, the Director shall consider current and expected operating conditions, together with experience gained during past operations of a similar nature in the area of proposed activities.

(3)(i) Except as provided in paragraph (a)(3)(ii) of this section, at the same time the lessee submits a development and production plan to the Director, an Environmental Report (Development/Production) shall also be submitted pursuant to the provisions of § 250.34-3(b). The report will not be considered part of the development and production plan; however, the report will accompany the plan through all review processes.

(ii) Submission of an Environmental Report will not be required for leases in the Gulf of Mexico, except as provided in paragraph (a)(3)(iii), or for leases any where on the OCS on which oil and gas in paying quantities had been discovered before enactment of the Act, unless the proposed activities would affect any land use or water use in the coastal zone of a State with a coastal zone management program approved pursuant to Section 306 of the Coastal Zone Management Act. Also, the Director may request specific environmental information to make the findings required under applicable law, including but not limited to, the Act and the National Environmental Policy Act.

(iii) Submission of an Environmental Report will be required for leases located in the eastern Gulf of Mexico.

(4) The Director may require the lessees of tracts on which oil or gas, or both, have been discovered in paying quantities and which are adjacent to or nearby the area covered in the development and production plan, to submit a preliminary description of their plans for development and production from those leases on adjacent or nearby areas.

(5) The lessee shall indicate which portions of the development and production plan the lessee believes are exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2). The lessee shall include a written discussion in the plan of the general subject matter of the deleted portions of the plan for transmittal to the recipients of copies of the plan identified in § 250.34-2(b)(1).

(6) A development and production plan shall not be deemed submitted until:

(i) The Director has determined that the plan and accompanyng Environmental Report are complete and contain the information required by §§ 250.34-2(a) and 250.34-3(b). The determination of whether a plan and accompanying Environmental Report are complete shall be made within 20 working days after the filing of the plan.

(ii) The plan is accompanied by (a) certificate(s) of coastal zone consistency as provided in 15 CFR Part 930, whenever the activities described would significantly affect any land use or water use in the coastal zone of any State with a coastal zone management program, approved pursuant to section 306 of the Coastal Zone Management Act.

(iii) The Director has been given the number of copies of a complete development and production plan and accompanying Environmental Report that the Director has determined is necessary for distribution pursuant to subsection 250.34-2(b)(1). The Director shall advise the lessee of the number of copies that are needed for distribution.

(b)(1) Within 10 days after a development and production plan has been deemed submitted, the Director shall publish a notice of receipt and transmit a copy of the plan, except for those portions of the plan determined to be exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2), and the accompanying Environmental Report to the Governor of each affected State, except as provided in paragraph (b)(2) of this section, the coastal zone management agency of each affected State that has a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act, and the executive of each affected local government that requests a copy. The Director shall also make copies of the plan and accompanying Environmental Report available to any appropriate federal agency, interstate regional entity, and the public, in accordance with established Departmental practices and procedures.

(2) The Governor of an affected State adjacent to the western Gulf of Mexico that does not have a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act may receive copies of development and production plans by submitting to the Director a written request for the documents. The Director shall notify the appropriate lessees immediately upon receipt of such a request. The Governor of Florida will receive copies of plans under the provisions of paragraph (b)(2) of this section.

(c)(1) The Governor of each affected State, the coastal zone management agency of each affected State that has a coastal zone management program approved pursuant to Section 306 of the Coastal Zone Management Act, and the executive of each affected local government shall have 60 days from the date of receipt of the development and production plan and accompanying Environmental Report to submit comments and recommendations to the Director. The executive of any affected local government must forward all recommendations to the Governor of the State prior to submitting them to the Director. In addition, any interested federal agency or person may submit comments and recommendations to the Director. All comments and recommendations shall be made available to the public in accordance with established Departmental practices and procedures.

(2) In the evaluation of a development and production plan, the Director shall accept recommendations of the Governor of each affected State and may accept the recommendations of the executive of an affected local government, if the Director determines, after having provided the opportunity for consultation, that the recommendations provide for a reasonable balance between the national interest and the well-being of the citizens of the affected State. In the evaluation of a plan, the Director shall also consider written comments by any appropriate federal agency, interstate regional entity and the public that are timely received. The Governor of each affected State shall be given, in writing, the reasons for rejecting the Governor's recommendations or for implementing any alternative means identified during consultations with the Governor.

(3)(i) When it is determined that activities proposed in a development and production plan will affect any land use or water use in the coastal zone of a State with a coastal zone management program approved pursuant to Section 306 of the Coastal Zone Management Act, the plan will be processed in accordance with the regulations in this section and the regulations governing Federal Coastal Zone Management Consistency Procedures (15 CFR Part 930).

(ii) The Governor of an affected State that does not have a coastal zone management program approved pursuant to Section 306 of the Coastal Zone Management Act may advise the Director that the State does not wish to receive or review development and production plans under section 19 of the Act.

(d) The Director shall review the environmental impacts of the activities described in the development and production plan pursuant to the provisions of § 250.34-4.

(e)(1) If the Director determines, subject to the provisions of Section 102(2)(C) of the National Environmental Policy Act, that approval of a development and production plan is a major Federal action significantly affecting the quality of the human environment, the Director shall transmit the draft environmental impact statement to the Governor of each affected State, the coastal zone management agency of each affected State that has a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act, and the executive of each affected local government that requests a copy. The Director shall also make copies of the environmental impact statement available to any appropriate federal agency, interstate entity, and the public, in accordance with established Departmental practices and procedures.

(2) Prior to or immediately after a determination by the Director that approval of a development and production plan requires that the procedures under the National Environmental Policy Act shall commence, the Director may require lessees of tracts in the vicinity, for which development and production plans have not been approved, to submit preliminary or

final plans for their leases.

(3) A determination by the Director that approval of a development and production plan requires commencement of the procedures under the National Environmental Policy Act shall have no effect upon the timeframe that a State with a coastal zone management program approved pursuant to section 306 of the Coastal Zone Management Act has to complete its coastal zone consistency review.

(f) After reviewing the record of any public hearing held with respect to the approval of a development and production plan for which an environmental impact statement is prepared, the Director shall within 60 days after the release of the final environmental impact statement, approve, require modification of, or disapprove the plan. Where no environmental impact statement is prepared, the Director shall, after reviewing all comments and recommendations submitted pursuant to paragraphs (c)(1) and (2) of this section, approve, require modification of, or disapprove a plan no later than 60 days after the last day of the comment period provided in paragraph (c)(1) of this section.

(g)(1) In the evaluation of a development and production plan, the Director shall consider whether the plan is consistent with:

(i) The provisions of the lease;

(ii) The provisions of the Act;

(iii) The provisions of regulations prescribed under the Act, including air quality regulations prescribed by the Secretary pursuant to section 5(a)(8) of the Act;

(iv) Other applicable Federal laws;

(v) Environmental, safety, and health requirements; and

(vi) The statutory requirement to protect property, natural resources of the OCS including any mineral deposits (in areas leased or not leased), and the national security or defense.

(2) The Director shall:

(i) Approve any plan which is consistent with the criteria in subparagraphs (g)(1)(i) through (vi) of this section;

(ii) Require the lessee to modify any plan which is inconsistent with the criteria in subparagraphs (g)(1)(i) through (vi) of this section; or

(iii) Disapprove any plan if the Director determines that:

(A) State concurrence with the applicant's coastal zone consistency certification has not been received, the State's concurrence has not been conclusively presumed, or the State objects to the consistency certification and the Secretary of Commerce does not make the determination authorized by section 307(c)(3)(B)(iii) of the Coastal Zone Management Act;

(B) Operations threaten national security or national defense; or

(C) Exceptional geological conditions in the lease area, exceptional resource value in the marine or coastal environmental, or other exceptional circumstances exist, and that (1) implementation of the plan would probably cause serious harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environments; (2) the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and (3) the advantages of disapproving the plan outweigh the advantages of development and production.

(3) The Director shall notify the lessee in writing of the reason(s) for disapproving a development and production plan or for requiring modification of a plan and the conditions which must be met for plan approval.

(h) The lessee may resubmit a development and production plan, as modified, to the Director. Within 60 days following the 60-day comment period provided for in paragraph (c)(1) of this section, the Director shall approve or disapprove the modified plan based upon the criteria in subparagraphs (g)(1) (i) through (vi) of this section.

(i)(1) If a development and production plan is disapproved for the sole reason that a State consistency certification has not been obtained, the Director shall approve the plan upon receipt of the concurrence, at the time when concurrence is conclusively presumed, or when the Secretary of Commerce makes a finding authorized by Section 307(c)(3)(B)(iii) of the Coastal Zone Management Act.

(2) If a development and production plan is disapproved because a State objects to the lessee's coastal zone consistency certification, the lessee shall modify the plan to accomodate the State's objection(s) and resubmit the plan to: (1) the Director for review pursuant to the criteria in subparagraphs (g)(1) (i) through (vi) of this section; and (2) through the Director, to the State for review pursuant to the Coastal Zone Management Act and the implementing regulations (15 CFR 930.83 and 930.84). Alternatively, the lessee may appeal the State's objection to the Secretary of Commerce pursuant to the procedures described in § 307 of the Coastal Zone Management Act and the implementing regulations (subpart H of 15 CFR 930). The Director shall approve or disapprove a plan, as revised, within 60 days following the 60-day comment period provided for in paragraph (c)(1) of this section.

(j) A modified development and production plan which has been disapproved pursuant to subsection (h) of this section may be revised in the same manner as, and with the same information required for, a new plan.

(k) Development and production plans disapproved pursuant to subparagraph (g)(2)(iii) or subsection (h) of this section are subject to

the provisions of section 25(h)(2) of the Act and the implementing regulations (30 CFR 250.12 and 43 CFR 3320.2).

(l)(1) The Director shall periodically review the activities being conducted under an approved development and production plan. The frequency and extent of the Director's review shall be based upon the significance of any changes in available information and in onshore or offshore conditions affecting or impacted by development or production activities being conducted pursuant to the plan. If the review indicates that the plan should be revised to meet the requirements of this Part, the Director shall require such revision pursuant to paragraph (l)(2) of this section.

(2) Proposals to revise an approved development and production plan, whether initiated by the lessee or ordered by the Director, shall be submitted to the Director for approval in the same manner as, and with the same information required for, a new development and production plan. When the Director determines that a proposed revision could result in a significant change in the impacts previously identified and evaluated, the revision shall be subject to all of the procedures in this section except those pertaining to the consistency requirements of the Coastal Zone Management Act. When the Director determines that a proposed revision calls for additional permits, the proposed revision shall be subject to all the procedures in this section. Information copies of all revisions to an approved plan will be forwarded by the Director to the recipients of the previously approved plan.

(3) When any revision to an approved development and production plan is proposed by the lessee, the Director may approve the revision if it is determined that the revision is consistent with the protection of the marine, coastal, and human environments and: will lead to greater recovery of oil and natural gas; improve the efficiency, safety, and environmental protection of the recovery operation; is the only means available to avoid substantial economic hardship to the lessee; or is otherwise not inconsistent with the provisions of the Act.

(m) Whenever the lessee fails to submit a development and production plan in accordance with provisions of this section or fails to comply with an approved plan, the lease may be cancelled in accordance with section (5)(c) and (d) of the Act and the implementing regulations (30 CFR 250.12 and 43 CFR 3320.2).

(n) In order to ensure that activities to be carried out under a proposed development and production plan and activities being carried out under an approved development and production plan are carried out in a safe and environmentally acceptable manner, the Director may authorize or direct the lessee to conduct geological, geophysical, or other surveys that the Director determines are necessary for evaluation of such activities. The lessee shall give the Director, upon request and without cost to the lessor, copies of any data obtained as a result of the surveys.

(o) The lessee may not drill any well until the Director's approval of an application for permit to drill, filed in accordance with the requirements of 30 CFR 250.41(a), has been received. Permit applications must conform to the activities described in detail in the related approved development and production plan, and shall not be subject to a separate State coastal zone consistency review.

(p) Nothing in this section shall be viewed as limiting the lessee's responsibility to take appropriate measures to meet emergency situations. In such situations, the Director may approve or require departures from an approved development and production plan.

(q) The lessee shall, contemporaneously with the submission to the U.S. Geological Survey, submit to the Federal Energy Regulatory Commission that portion of any development and production plan which relates to production of natural gas and the facilities for transportation of natural gas.

[43 FR 3884, Jan. 27, 1978; 44 FR 53693, Sept. 14, 1979; 45 FR 20465, Mar. 28, 1980; 45 FR 37818, June 5, 1980]

§ 250.34-3 Environmental Report.

(a) Environmental Report (Exploration). At the same time the lessee submits an exploration plan to the Director, an Environmental Report (Exploration) shall be submitted, except as provided for in § 250.34-1(a)(2)(ii). The report shall identify the name of the lessee or operator and the lease(s) involved. The report should be in summary form and shall include information available at the time the related exploration plan is submitted to the extent that such information is accurate, current, and applicable to the geographic area and the proposed activities covered by the plan. The lessee shall refer to information and data contained in the related plan, other Environmental Reports, and other environmental analyses and impact statements prepared for the geographic area by identifying the information and indicating a source for obtaining copies of the cited materials. Information and data which are site specific or which are developed subsequent to the most recent environmental impact statement or other environmental impact statements and analyses in the immediate area shall be specifically considered. The Environmental Report (Exploration) shall include the following:

(1) To the extent that information is not contained in the related exploration plan, the Environmental Report shall contain:

(i) A brief description of the following:

(A) The procedures, personnel, and equipment that are to be used for preventing, reporting, and cleaning up spills of oil or waste materials which may occur during the exploration activities, including information on response time, capacity, and location of equipment and sites and methods of disposal;

(B) The location, size, number and land requirements (including rights-of-way and easements) of onshore support and storage facilities, and, where possible, a timetable regarding the acquisition of lands and the construction or expansion of any facilities;

(C) The estimated number of persons expected to be employed in support of offshore, onshore, and transportation activities, and, where possible, the approximate number of new employees and families likely to move into the affected area;

(D) The most likely travel routes for boat and aircraft traffic between offshore and onshore facilities, the probable location of onshore terminals, and the estimated frequency such routes will be traversed;

(E) The quantity and composition of solid and liquid wastes and pollutants likely to be generated by offshore, onshore, and transport operations;

(F) Major supplies, services, energy, water, or other resources within affected States necessary for carrying out the related plan;

(G) Environmentally sensitive or potentially hazardous areas, including:

(1) Site specific geology, e.g., bathymetry, seismicity, extent and type of bottom sediments, and geologic features which pose a potential hazard to the activities proposed;

(2) Historic patterns and other meteorological conditions including storm frequency and magnitude, wind direction and velocity, of offshore areas; listing, where possible, the means and extremes of each;

(3) Physical oceanography including onsite direction and velocity of currents;

(4) Onsite flora and fauna including bottom communities, where present, transitory birds and mammals that may be in the area when proposed activities are being conducted, identification of endangered species and their habitats that could be affected by proposed activities, and typical fishing seasons of the area;

(5) Environmentally sensitive areas (onshore as well as offshore), e.g., refuges, preserves, sanctuaries, rookeries, calving grounds, and areas of particular concern identified by an affected State pursuant to the Coastal Zone Management Act which may be affected by the proposed activities; and

(6) Onsite uses of the area, e.g., shipping, military use, recreation, boating, and commercial fishing;

(7) Archeological and cultural resources located within the area that may be disturbed by the proposed activities;

(8) Existing and planned monitoring systems that are measuring or will measure environmental conditions and provide information and data on the impacts of activities in the geographic areas.

(ii) An assessment of the direct effects on the offshore and onshore environments expected to occur as a result of implementation of the exploration plan, expressed in terms of magnitude and duration, with special emphasis upon the identification and evaluation of unavoidable and irreversible impacts on the environment.

(iii) For leases in the western Gulf of Mexico, the Director, after consultation with the Office of Coastal Zone Management and the affected State(s) with (an) approved coastal zone management program(s), may limit the amount of information required to be included in an Environmental Report to those parts of paragraphs 250.34-3(a)(1) (i) and (ii) of this section necessary for the State's review and concurrence with the consistency determination, considering operating conditions, operating experience, and existing facilities in the area of proposed activities. The Director shall advise the lessee of the amount of information required to be included in an Environmental Report.

(2) Such other information and data as the Director may require.

(3) The name, address, and telephone number of an individual employee of the lessee to whom inquiries by the Director and the affected State(s) may be made.

(4)(i) For onshore activities directly associated with a proposed OCS facility, the lessee shall provide information on each source of air pollutants, listing: The source; the location of each source; the chemical composition and quantity of air pollutants; and the frequency and duration of emissions.

(ii) For each OCS facility, the lessee shall review the requirements of § 250.57, and shall submit only that information, described below, needed to make the findings under § 250.57:

(A)(1) Projected emissions from each proposed or modified facility for each year of operation, and the basis for all calculations, to include: (i) For each source: The source, the amount of the emission by air pollutant expressed in tons per year, and the frequency and duration of emissions; (ii) For each facility: The facility, the total amount of emissions by air pollutant expressed in tons per year, and in addition, for a modified facility only, the incremental amount of total emissions by air pollutant resulting from the new or modified source or sources; (iii) A detailed description of all processes, process equipment, and storage units, including information on fuels to be burned; (iv) A schematic drawing which identifies the location and ele-

vation of each source; and (v) If projected emissions are based on the use of emission reduction control technology, a description of the controls providing the information required by paragraph (a)(4)(ii)(D) of this section. If a mobile drilling vessel has been described in an earlier Environmental Report, the lessee may reference, consistent with the limitations described in paragraph (a) of this section, the information in that report pertaining to paragraphs (a)(4)(ii)(A)(1)(iii), (iv) and (v).

(2) The distance of each proposed facility from the mean high water mark (mean higher high water mark on the Pacific Coast) of any State.

(B)(1) The model or models used to determine the effect on the onshore air quality of emissions from each facility, or from other facilities when required by the Director, and the results obtained through the use of the model or models. The model or models must be approved for use by the Director.

(2) The best available meteorological information and data consistent with the model or models used, stating the basis for the information and data selected.

(C) The air quality status of any onshore area where the air quality is significantly affected by projected emissions from each facility proposed in the plan. The area should be classified as nonattainment, attainment, or unclassifiable, to include: The status of each area by air pollutant; the class of attainment areas; and the air pollution control agency whose jurisdiction covers the area identified.

(D) The emission reduction control technology available to reduce emissions, to include: The source, the emission reduction control technology; the reductions achieved; and the monitoring system the lessee proposes to use to measure emissions. If applicable, the lessee shall indicate which emission reduction control technology the lessee believes constitutes BACT and the basis for that opinion.

(b) Environmental Report (Development/Production). At the same time the lessee submits a development and production plan to the Director, an Environmental Report (Development/Production) shall be submitted, except as provided for in § 250.34-2(a)(2)(ii). The report shall identify the name of the lessee or operator and the lease(s) involved. The report shall be as detailed as necessary to enable identification and evaluation of the environmental consequences of the proposed activities and shall include information available at the time the related plan is submitted to the extent that such information is accurate, current, and applicable to the geographic area and activities covered by the plan. The lessee shall refer to information and data contained in the related plan, other Environmental Reports, and other environmental analyses and impact statements prepared for the geographic area by identifying the information and data and indicating a source for obtaining copies of the cited material. Information and data which are site-specific or which are developed subsequent to the most recent environmental impact statement or other environmental impact statements and analyses in the immediate area shall be specifically considered. The Environmental Report (Development/Production) shall include the following:

(1) To the extent that information is not contained in the related development and production plan, the Environmental Report shall contain:

(i) A brief description of the following:

(A) The location, description, and size of any offshore and, to the maximum extent practicable, land-based operations to be conducted or contracted for as a result of the proposed activity. This shall include:

(1) The acreage required within a State for facilities, rights-of-way, and easements;

(2) The means proposed for transportation of oil and gas to shore, the routes to be followed by each mode of transportation, and the estimated quantities of oil or gas, or both, to be moved along such routes;

(3) An estimate of the frequency of boat and aircraft departures and arrivals, the onshore location of terminals, and the normal routes for each mode of transportation; and

(4) The quantities, types, and plans for disposal of solid and liquid wastes and pollutants likely to be generated by offshore, onshore, and transport operations, and regarding any wastes which may require onshore disposal, the means of transportation to be used to bring the wastes to shore, the disposal methods to be utilized, and the location of onshore waste disposal or treatment facilities.

(B) The requirements for land, labor, material, and energy for the items identified above, including:

(1) The approximate number, timing, and duration of employment of persons who will be engaged in onshore development and production activities, and approximate number of local personnel who will be employed for or in support of the development activities (classified by the major skills or crafts that will be required from local sources and estimated number of each such skill needed), and the approximate total number of persons who will be employed during the onshore construction activity and during all activities related to offshore development and production;

(2) The approximate number of people and families to be added to the population of local near-shore areas as a result of the planned development;

(3) An estimate of significant quantities of energy and resources to be used or consumed, including electricity, water, oil and gas, die-

sel fuel, aggregate, or other supplies, which may be purchased within an affected State; and

(4) The types of contractors or vendors which will be needed, although not specifically identified, and which may place a demand on local goods and services.

(C) A schedule setting forth specific nearshore and onshore development activities which correspond to the offshore development and production activities described in detail in the related plan. To the maximum extent possible, individal activities are to be projected on a year-to-year basis. The schedule shall include:

(1) The sequence in which events are expected to be accomplished;

(2) An estimate of the time required to complete specific activities;

(3) The month and year that specific actions are most likely to occur onshore and offshore; and

(4) The month and year that other pertinent activities associated with development of onshore and offshore facilities are likely to be accomplished.

(D) A description of any environmental monitoring systems proposed for use by the lessee.

(E) A description of the contingency plans that are in effect for the area to be developed together with a discussion of the pollution-prevention and cleanup equipment that is or will be maintained on the drill site and in the area pursuant to a Regional Contingency Plan.

(F) A narrative description of the existing environment, with an emphasis placed on those environmental values that may be affected by the proposed action. This section shall contain a description of the physical environment of the area covered by the related plan. This portion of the report shall include data and information obtained or developed by the lessee together with other pertinent information and data available to the lessee from other sources. The information and data to be included in the lessee's report on the environment shall include, where appropriate:

(1) Summary conclusions of cultural and historical resource surveys of the lease(s) or unit area;

(2) The seafloor configuration, stability, foundation characteristics, sedimentation, and erosion potential at the site of structural components described in the plan;

(3) The seismic risk and conditions including geophysical high-resolution surveys of sites, routes, and corridors;

(4) The aquatic biota, including a description of fishery and marine mammal significance and utilization of the lease or unit area;

(5) The predevelopment ambient water column quality and temperature data for incremental depths for the area encompassed by the plan;

(6) The physical oceanography, including ocean currents described as to prevailing direction, seasonal variations, and variations at different depths in the lease(s) or unit area;

(7) Historic patterns and other meterologic conditions, including storm frequency and magnitude, wind direction and velocity, and ambient air quality, listing, where possible, the means and extremes of each;

(8) The other uses of the area such as military use for national security or defense; and

(9) The existing or planned monitoring systems that are currently measuring impacts of activities on the environment in the lease sale area.

(ii) An assessment of the effects on the environment expected to occur as a result of implementation of the related plan. This section of the report shall identify specific and cumulative impacts that may occur both onshore and offshore and measures proposed to mitigate these impacts. Such impacts shall be quantified to the fullest extent possible and shall be accumulated for all activities for each of the major elements of the environment (i.e., water, biota, etc.). In every case, impacts shall be expressed in terms of magnitude and duration. The report shall place special emphasis upon the identification and evaluation of unavoidable and irreversible impacts on the environment and additional environmental monitoring systems that may be needed to provide accurate reporting of cumulative impacts on the environment.

(iii) A discussion of alternatives to the activities proposed that were considered during the development of the related plan; for example, a comparison of development and production operations using a bottom-supported platform which extends above the surface of the ocean with a similar degree of oil and gas development using seafloor completion and production techniques. Any significant differences in the environmental impacts of the use of alternative technologies shall be identified and discussed.

(iv) For leases in the western Gulf of Mexico, the Director, after consultation with the Office of Coastal Zone Management and the affected State(s) with (an) approved coastal zone management program(s), may limit the amount of information required to be included in an Environmental Report (Development/Production) to those parts of § 250.34-3(b)(1)(i) through (iii) of this section necessary for the State's review and concurrence with the consistency determination, considering operating conditions, operating experience, and existing facilities in the area or proposed activities.

(2) Such other information and data as the Director may require.

(3) The name, address, and telephone number of an individual employee of the lessee to whom inquiries by the Director and the affected State(s) may be directed.

(4)(i) For onshore activities directly associated with a proposed OCS facility, the lessee shall provide information on each source of air pollutants, listing: The source; the location of each source; the chemical composition and quantity of air pollutants; and the frequency and duration of emissions.

(ii) For each OCS facility the lessee shall review the requirements of § 250.57, and shall submit only that information, described below, needed to make the findings under § 250.57.

(A)(1) Projected emissions from each proposed or modified facility for each year of operation, and the bases for all calculations, to include: (i) For each source: the source, the amount of the emission by air pollutant expressed in tons per year, and the frequency and duration of emissions; (ii) For each proposed facility: The facility, the total amount of emissions by air pollutant expressed in tons per year, the frequency distribution of total emissions by air pollutant expressed in pounds per day, and in addition, for a modified facility only, the incremental amount of total emissions by air pollutant resulting from the new or modified source or sources; (iii) A detailed description of all processes, process equipment, and storage units, including information on fuels to be burned; (iv) A schematic drawing which identifies the location and elevation of each source; and (v) If projected emissions are based on the use of emission reduction control technology, a description of the controls providing the information required by paragraph (b)(4)(ii)(D)(1) of this section.

(2) The distance of each proposed facility from the mean high water mark (mean higher high water mark on the Pacific Coast) of any State.

(B)(1) The model or models used to determine the effect on the onshore air quality of emissions from each facility, or from other facilities when required by the Director, and the results obtained through the use of the model or models. The model or models must be approved for use by the Director.

(2) The best available meteorological information and data consistent with the model or models used, stating the basis for the information and data selected.

(C) The air quality status of any onshore area where the air quality is significantly affected by projected emissions from each facility proposed in the plan. The area should be classified as nonattainment, attainment, or unclassifiable listing: The status of each area by air pollutant; the class of attainment areas; and the air pollution control agency whose jurisdiction covers the area identified.

(D)(1) The emission reduction control technology available to reduce emissions, listing: The source; the emission reduction control technology; the reductions achieved; and the monitoring system the lessee proposes to use to measure emissions. If applicable, the lessee shall indicate which emission reduction control technology the lessee believes constitutes BACT and the basis for that opinion.

(2) The ownership of the offshore and onshore offsetting source or sources, and the reduction obtainable from each offsetting source.

[43 FR 3885, Jan. 27, 1978; 44 FR 53693, Sept. 14, 1979; 45 FR 15143, Mar. 7, 1980]

§ 250.34-4 Compliance with the National Environmental Policy Act (NEPA).

(a) Prior to approval of an exploration or development and production plan, or approval of significant revisions to an approved exploration or development and production plan, the Director shall review the environmental impacts of the activities proposed in accordance with applicable policies and guidelines to determine whether the proposed exploration activities, or development and production activities, should be approved, and whether approval of the proposed activities constitutes a major federal action significantly affecting the quality of the human environment requiring preparation of an Environmental Impact Statement pursuant to Section 102(2)(C) of the National Environmental Policy Act and the implementing regulations. In the preparation of documents that present evaluations of the environmental impacts expected to result from the conduct of the activities described in the plan, the Director may utilize information contained in the lessee's Environmental Report.

(b) During the review conducted in accordance with subsection (a) above, the Director shall give particular attention to:

(1) The location and design of exploration, development, and production facilities which are proposed for installation in areas of high seismic risk or seismicity;

(2) The location and design of exploration, development, and production facilities which are proposed for installation within or near the boundary of a marine sanctuary, wildlife refuge, or other areas of high ecological sensitivity;

(3) The location of bottom-founded structures in areas of potentially hazardous natural bottom conditions; and

(4) The use of new or unusual technology.

(c) An Environmental Impact Statement shall be prepared when the Director determines that the impacts of activities described in the new or revised plan constitute a major federal action significantly affecting the quality of the human environment and have not been adequately considered in a previous Environmental Impact Statement. In this regard, the Director shall consider:

(1) Whether implementation of the activities described in the new or revised plan would require construction of new onshore processing,

storage, treatment, or transportation facilities which could have significant adverse impacts upon the marine, coastal, or human environments;

(2) Whether the cumulative impact of the proposed activities have been previously considered, or whether the impacts are significantly greater than those previously analyzed; and

(3) The likelihood of adverse impacts on the marine, coastal, or human environments that differ significantly in magnitude, duration, or nature from the impacts previously analyzed.

(d) The Director shall declare the approval of a development and production plan in any area or region (as defined by the Director) of the OCS, except in the western Gulf of Mexico, to be a major federal action at least once pursuant to subsection 25(e) of the Act.

(e) Where it has been determined that an Environmental Impact Statement will be prepared, the Director shall decide whether the Statement will cover the activities described in a single development and production plan or those described in a number of such plans covering an area of the OCS where there is a liklihood of significant development. In the preparation of an Environmental Impact Statement, the Director may utilize information in any relevant Environmental Impact Statement or any other document previously prepared during or as a result of an environmental review where that action serves to reduce repetition and to expedite or facilitate the conduct and completion of the National Environmental Policy Act process.

[43 FR 3887, Jan. 27, 1978; 44 FR 53693, Sept. 14, 1979]

§ 250.35 Effect of drilling or well reworking on lease term.

(a) Drilling or well reworking operations on a leased area, which have been approved pursuant to the regulations in this Part, shall continue the lease in effect so long as the drilling or well reworking operations are conducted no more than 90 days before the expiration of the primary term. A lease continued beyond its primary term by production or by drilling or well reworking operations shall be continued in effect by production or by drilling or well reworking operations which are commenced on or before the 90th day after the date of last production or on or before the 90th day after the date of the completion of the last drilling or well reworking operations. No time lapse in drilling or well reworking activities of greater than 90 days shall be deemed to be prompt and efficient unless operations on the lease have been suspended pursuant to § 250.12 of this Part.

(b) The provisions of this section do not affect the lessee's obligation to obtain the Director's prior approval of a plan of exploration, or a plan of development and production under § 250.34 of this Part, or of a notice of intention to drill or rework a well under § 250.36 of this Part, or of complying with the other provisions of the regulations in this Part.

[24 FR 9527, Nov. 28, 1959; 34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.36 Applications for permit to drill, deepen, or plug back.

(a) Applications for permits to drill, deepen, or plug back wells must be filed on Form 9-331C. The Director shall advise the lessee concerning the number of copies of Form 9-331C to be submitted. Except as provided in section 250.13 of this Part, written approval must be received from the Director prior to commencing operations.

(b)(1) An application for a permit to drill must include the following: the surface location and projected bottom-hole location of the well(s), in feet, from the lease boundaries; the elevation of the derrick floor; the water depth; the estimated depth to which the well will be drilled; the estimated depths to the top of significant marker formations; the estimated depths at which encounters with water, oil, gas, and mineral deposits are expected; the proposed blowout-prevention and casing programs including the size, weight, grade, and setting depth of casing and the pressure rating of blowout prevention equipment; the estimated quantity of cement that will be used; and all other information specified on Form 9-331C. Information shall also be furnished relative to: plans for drilling other wells from the same platform; plans for coring at specified depths; plans for electrical and other logging operations; and such other information as may be required by the Director.

(2) At least two copies of the application shall be accompanied by a certified plat, drawn to a scale of 2,000 feet to the inch, showing the surface and subsurface location of the well(s) to be drilled and all the wells previously drilled in the vicinity for which information is available.

(c) An application for a permit to deepen or plug back must include the following: the present status of the well, including the production string or last string of casing; the well depth; the present productive zones and productive capability; and all other information specified on Form 9-331C. The application must be accompanied by a justification for and details of the proposed work.

[34 FR 13548, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.37 Marking platforms, structures, and wells.

(a) The lessee shall mark each drilling platform or structure. All markings shall include the name of the lessee or operator, the name of the area, the block number, and the platform or structure designation. Letters and figures not less than 12 inches in height are to be used and the markings are to be placed on the diagonal corners of the platform or structure.

(b) Each well must be clearly identified by a sign containing the well number and the OCS lease number.

(c) The lessee shall preserve these markings and signs in good repair.

[19 FR 2658, May 8, 1954; 34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.38 Well records.

(a) The lessee shall keep at its field headquarters, or at other locations conveniently available to the Director, accurate and complete records for each well and of all well operations, including: production, drilling, logging, directional well surveys, casing, perforating, safety devices, redrilling, deepening, repairing, cementing, alterations to casing, plugging, and abandoning. The records shall contain: a description of any unusual malfunction, condition, or problem; all the formations penetrated; the content and character of oil, gas, and other mineral deposits and water in each formation; the kind, weight, size, grade, and setting depth of casing; and all other information required by the Director.

(b)(1) Upon request by the Director, the lessee shall immediately transmit copies of the records of any of the well operations specified in paragraph (a) of this section. In any event, the lessee shall, within 30 days after completion of any well, transmit to the Director duplicate copies of the records of all operations on, or attached to, Form 9-330 (see section 250.95 of this Part). When operations are suspended, or temporarily prohibited, the lessee shall, within 30 days after the suspension or temporary prohibition or completion of any further operations, transmit to the Director duplicate copies of the records of all operations conducted during the suspension or temporary prohibition on, or attached to, Form 9-330 or Form 9-331 (see §§ 250.92 and 250.95 of this Part), as appropriate.

(2) Upon request by the Director, the lessee shall submit paleontological reports identifying microscopic fossils by depth unless washed samples of drill cuttings, normally maintained by the lessee for paleontological determinations, are made available to the Director for inspection.

(3) Upon request by the Director, the lessee shall furnish copies, in a manner and form prescribed by the Director, of the daily drilling report and a plat showing the location, designation, and status of all wells on the leased lands.

(4) Upon request by the Director, the lessee shall furnish legible, exact copies of service company reports on cementing, perforating, acidizing, analyses of cores, or other similar services.

(c) If the Director determines that circumstances warrant, the lessee shall submit any other reports and records of operations, in the manner and form prescribed by the Director.

[34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.39 Tests, surveys, and samples.

(a) The lessee shall make adequate tests or surveys, in a manner acceptable to the Director and without cost to the lessor, to determine: the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, other mineral deposits, or water, the amount and direction of deviation of any well from the vertical; and the formation, casing, tubing, and other pressures.

(b) The lessee shall take formation samples or cores to determine the identity, fluid content, and character of any formation, in accordance with requirements prescribed by the Director in the approval of the notice to drill or redrill any well.

[19 FR 2658, May 8, 1954; 34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.40 Directional survey.

(a) An angular deviation and directional survey shall be made from the surface to the total depth of each well.

(b) The Director, at the request of an owner of an adjoining lease, may furnish a copy of the directional survey to the owner of an adjoining lease.

[19 FR 2658, May 8, 1954; 34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.41 Control of wells.

(a)(1) The lessee shall take all necessary precautions to keep its wells under control at all times. The lessee shall only utilize personnel who are trained and competent to drill and operate wells, and shall utilize and maintain materials and properly designed pressure fittings and equipment necessary to assure the

safety of operating conditions and procedures. Casing, cementing, drilling mud, and blowout prevention programs for well drilling operations shall take into account the depths at which various fluid- or mineral-bearing formations are expected to be penetrated, the formation fracture gradients and pressure expected to be encountered, and other pertinent geologic and engineering information and data about the area.

(2) The lessee shall case and cement all wells with a sufficient number of strings of casing in a manner necessary to: prevent release of fluids from any stratum through the well bore (directly or indirectly) into the sea; prevent communication between separate hydrocarbon-bearing strata (except strata approved for commingling) and between hydrocarbon-and water-bearing strata; protect freshwater strata from contamination; support unconsolidated sediments; and otherwise provide a means of control of the formation pressures and fluids. The lessee shall install casing strong enough to withstand collapse, bursting, tensile and other stresses. The casing shall be cemented in a manner which will anchor and support the casing. Safety factors in the casing program design shall be of sufficient magnitude to provide optimum well control during drilling and to assure safe operations for the life of the well. The lessee shall install structural or drive casing to provide hole stability for the initial drilling operation. A conductor string of casing (the first string run other than any structural or drive casing) must be cemented with a volume of cement sufficient to circulate back to the seafloor, however, if authorized by the Director, cement may be washed out or displaced to a specified depth below the seafloor to facilitate casing removal upon well abandonment. All subsequent strings must be securely cemented.

(3) The lessee shall maintain, readily accesible for use, quantities of drilling mud sufficient to assure well control. The lessee's testing procedures, characteristics, and use of drilling mud and conduct of related drilling procedures shall prevent blowouts or other loss of well control. Mud testing equipment and mud volume measuring devices shall be maintained in an operable condition at all times, and mud tests shall be performed frequently and recorded on the driller's log.

(4) The lessee shall install, use, and test blowout preventers and related well-control equipment in a manner necessary to prevent blowouts. In no event shall the lessee conduct drilling below the conductor string of casing until the installation of at least one remotely controlled blowout preventer and equipment for circulating drilling fluid to the drilling structure or vessel. Blowout preventers and related well-control equipment shall be pressure tested when installed, after each string of casing is cemented and at other times prescribed by the Director. Blowout preventers shall be activated frequently to test for proper functioning. All blowout-preventer tests shall be recorded on the driller's log.

(b) After wells are completed, the lessee shall take all necessary steps to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. For wells capable of flowing oil, gas, or formation fluids, the lessee shall install and maintain in operating condition subsurface-safety devices. For all producing wells including wells not capable of flowing oil, gas, or formation fluids, the lessee shall install and maintain surface safety valves with automatic shutdown controls and shall conduct tests or surveys designed to determine the effects of corrosive or erosive substances on well and production equipment. The lessee shall, as prescribed by the Director, periodically test and inspect all devices and equipment, and shall record the results of all tests.

[34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.42 Treatment of production.

The lessee shall put into marketable condition, if commercially feasible, all products produced from the leased land. In calculating the royalty payment, the lessee may not deduct the costs of treatment.

[19 FR 2658, May 8, 1954; 34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.43 Pollution and waste disposal.

(a)(1) The lessee shall not pollute the land or water, harm or damage fish and other aquatic life, or allow extraneous matter to enter and damage any mineral- or water-bearing formation.

(2) The lessee shall dispose of all waste material in a manner approved by the Director.

(3) All spills or leakage of oil or waste materials shall be recorded by the lessee and shall be reported to the Director. All spills or leakage of oil or waste materials of a size or quantity specified by the appropriate agent of the Federal Government under the pollution-contingency plan shall be reported also by the lessee, without delay, to the agent specified in the plan.

(b)(1) When pollution occurs as a result of operations conducted by or on behalf of the lessee, and the pollution damages or threatens to damage life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), or the marine, coastal, or human environment, the control and total

removal of the pollution shall be at the expense of the lessee.

(2) Upon failure of the lessee to control and remove the pollution, the Director, in cooperation with other appropriate agencies of Federal, State, and local governments, or in cooperation with the lessee, or both shall have the right to control and remove the pollution in accordance with any established pollution-contingency plan for combating oil spills, or by other means, at the expense of the lessee. Such action shall not relieve the lessee of any responsibility provided for in the pollution-contingency plan or otherwise provided by law.

(c) The lessee's liability shall be governed by applicable law, including the Offshore Oil Spill Pollution Fund provisions of Title III of the Act.

[34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.44 Borehole abandonment.

The lessee shall promptly plug and abandon any borehole on the leased land that the Director determines is no longer useful. However, no well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the Director. Before abandoning a well that has been capable of producing oil or gas in paying quantities, the lessee shall submit to the Director for a statement containing the reasons for abandonment and detailed plans for carrying out the necessary work (see § 250.92 of this Part). A well may be abandoned only after receipt of written approval by the Director. No well shall be plugged if the plugging operation would jeopardize safe and economic operations of nearby wells. The manner and method of plugging must be approved or prescribed by the Director. Equipment shall be removed, and premises at the site properly conditioned immediately after plugging operations are completed.

Drilling equipment shall not be removed from any suspended drilling operation without taking adequate measures, as approved or prescribed by the Director, to protect life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), and the marine, coastal, or human environment.

[19 FR 2658, May 8, 1954; 34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.45 Accidents, fires, and malfunctions.

(a)(1) In the conduct of all its operations, the lessee shall take all steps necessary to prevent accidents and fires. The lessee shall immediately notify the Director of all serious accidents, any death or serious injury, and all fires connected with any activity or operation pursuant to the lease. For the purpose of this section, a serious injury is one resulting in absence from work for 72 or more hours.

(2) Within 10 days of all serious accidents, the lessee shall submit a written report on any death or serious injury and on all fires connected with any activity or operation pursuant to the lease.

(b) The lessee shall notify the Director of any other unusual condition, problem, or malfunction connected with any activity or operation pursuant to the lease within 24 hours of its occurrence.

[34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.46 Safe and workmanlike operations.

(a) The lessee shall perform all operations in a safe and workmanlike manner and shall maintain all equipment in a safe condition for the protection of the lease and associated facilities, for the health and safety of all persons, and for the preservation and conservation of property and the environment.

(b) The lessee shall immediately take all necessary precautions to control, remove, or otherwise correct any hazardous oil and gas accumulations or other health, safety, or fire hazard.

[34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.47 Sales contracts.

The lessee shall file with the Director, within 30 days after their effective date, a copy of all contracts, including all contract modifications (e.g., amendments and terminations), for the disposal of lease products. Nothing in any such contract shall be construed or accepted as modifying any of the provisions of the lease.

[34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.49 Royalty, net profits share, and rental payments.

As specified under the provisions of the lease, the lessee shall pay all rental when due, and shall pay in value or deliver in production all royalties and net profit shares in the amounts of value or production determined by the Director to be due. Payment of rentals, royalties, and net profit shares in value shall be by electronic transfer of funds or by check or draft on a solvent bank or by money order drawn to the order of the U.S. Geological

Survey. Failure to make timely payment of rental, royalty, or net profit share will result in the collection of the amount due plus interest from the date due until the date of payment. Interest shall be calculated at the average of the highest rate for commercial and finance company paper of maturities of 180 days or less obtaining on each of the days incurred within the period for which interest is due. Such failure may also result in the initiation of enforcement proceedings.

[21 FR 4668, June 27, 1956; 34 FR 13546, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.50 Authority and requirements for unitization.

(a) Unitization may be required or approved by the Director for the prevention of waste and the conservation of the natural resources of the OCS, and for the protection of correlative rights therein, including the protection of Federal royalty interests. Unitization may be required or approved for exploration, development, and/or production. Lessees may agree among themselves to unitization, subject to the Director's approval (voluntary unitization), or the Director may impose unitization on the initiation of one or more lessees or on the Director's own initiative (compulsory unitization).

(b) A unit area shall include the minimum number of leases or segregated portions of leases required to permit one or more, or a portion of one or more, mineral reservoirs or potential hydrocarbon accumulations to be served by an optimal number of artificial islands, installations, or other devices necessary for the efficient exploration for or development and production of oil and gas or other minerals. The Director shall conditionally approve the development and production of unitized substances on the lessees' acceptance of any necessary adjustment in the unit area. Procedures for adjustment of a unit area shall be set forth in the unit agreement.

(c) Unitization may not be required or approved by the Director until he finds that the delineation of any reservoir or any potential hydrocarbon accumulation has been reasonably established.

(d) A unit agreement shall provide for the appointment of a unit operator and the allocation of costs and benefits to the unitized leases. In the absence of an agreed basis for the allocation of costs and benefits, or under unitization required by the Director, costs and benefits shall be allocated on an equitable basis determined by the Director, as supported by the record compiled in accordance with 30 CFR 250.51.

(e) Drilling, production, and well reworking operations performed in accordance with a unit agreement shall be deemed to be performed for the benefit of all leases or segregated portions of leases that are subject to the unit agreement. Plans may provide for the cessation of actual drilling activities for a reasonable period between the discovery and delineation of one or more reservoirs and the initiation of actual development and production to allow for the expeditious design, fabrication, and installation of artificial islands, installations, and other devices needed for development and production operations. When plans that call for the cessation of drilling prior to actual production involve one or more leases beyond their primary term, the plans shall be accompanied by a request and supporting justification for a suspension of operations or production pursuant to 30 CFR 250.12.

(f) A unit agreement shall be effective on the date specified in the unit agreement and shall terminate when unitized substances are no longer being produced or drilling or well reworking operations are no longer being conducted under the unit agreement, unless the Director has ordered or approved a suspension of operations or production pursuant to 30 CFR 250.12.

(g)(1) A lease embracing OCS submerged lands that are part within and part outside of a unit area shall be segregated into separate leases as to the portion committted to the unit agreement and the portion not committed, and the terms of such lease shall apply separately to such segregated portions as of the effective date of unitization. A lease, including the segregated unitized portion of a lease, shall continue in force for the term of the lease and as long thereafter as it remains subject to an approved unit agreement.

(2) A segregated portion of a lease which is not subject to a unit agreement may be maintained after the effective date of unitization only for the term provided in the lease. Drilling, production, or well reworking within the unit area shall not be for the benefit of an excluded lease or the excluded segregated portion of a lease.

(h) Upon the expiration or termination of a unit agreement or when there is an adjustment of a unit area that results in the elimination of a lease or a portion of a lease from the unit agreement, each lease or segregated portion of a lease that was but is no longer subject to the unit agreement shall expire unless: (1) Its initial term has not expired, (2) drilling, production, or well reworking operations are underway on the lease or portion of a lease, or (3) a suspension of production or operations has been ordered or approved for the lease or portion of a lease pursuant to 30 CFR 250.12.

(i) When a lease or a segregated portion of a lease subject to a unit agreement is beyond the initial fixed term of the lease and unitized substances are not being produced, the lease or

segregated portion of a lease shall expire unless: (1) The unit operator conducts a continuous drilling or well reworking program designed to develop or restore the production of unitized substances, or (2) a suspension of operations has been ordered or approved in accordance with 30 CFR 250.12.

(j) If a lease issued prior to May 2, 1980, is included in a unit agreement, the provisions of § 250.50(g) shall not apply without the consent of the lessee. If any such lease is subject in whole or part to unitization, the entire lease shall continue in force for the term provided in the lease and as long thereafter as the lease or a portion thereof remains part of the unit area and as long as there are operations within the unit area which serve to continue the lease in effect.

[29 FR 4563, Mar. 31, 1964; 34 FR 13547, Aug. 22, 1969; 45 FR 20465, Mar. 28, 1980; 45 FR 29285, May 2, 1980]

§ 250.51 Procedures for unitization.

§ 250.51-1 Voluntary unitization.

(a) Lessees seeking approval of unitization shall draft a unit agreement conforming to the model unit agreement. For good cause the Director may require or, upon request, approve a variation from the model unit agreement. Any request for variation shall be made at the time the proposed unit agreement is submitted to the Director for approval and shall include an explanation of the reasons for the variation. If the Director requires a variation from the model unit agreement, lessees shall be so informed at the time approval is given for a proposed unit agreement or at the time an order requiring unitization is issued.

(b) Lessees who seek approval of a unit agreement shall file a request with the Director accompanied by a proposed unit agreement conforming to the model unit agreement, and by the supporting geological and geophysical data and any other information that may be necessary to show that the proposed unitization meets the criteria of 30 CFR 250.50. If the Director approves the proposed unit agreement, lessees shall execute the unit agreement and file with the Director a counterpart in triplicate executed by each lessee. Where all lessees of the proposed unit area have executed the unit agreement, the Director may issue an order or orders approving unitization if he finds that unitization would be in accordance with 30 CFR 250.50.

[29 FR 4563, Mar. 31, 1964; 34 FR 13547, Aug. 22, 1969; 38 FR 10001, Apr. 23, 1973; 45 FR 29285, May 2, 1980]

§ 250.51-2 Compulsory unitization.

(a) If the Director requires unitization on his own initiative or in conjunction with an application for approval of unitization by less than all lessees of the proposed unit area, unitization shall be imposed according to a unitization plan which shall:

(1) Conform to the model unit agreement, unless good cause exists for variation from the model unit agreement and the reasons for the variation are stated in writing; and

(2) Conform to any proposed unit agreement executed by less than all of the lessees, unless good cause exists for variation from the proposed unit agreement and the reasons for the variation are stated in writing.

(b)(1) Lessees who seek compulsory unitization shall file a request with the Director accompanied by a proposed unit agreement conforming to the model unit agreement, together with supporting geological and geophysical data and any other information that may be necessary, to show that unitization meets the criteria of 30 CFR 250.50. The proposed unit agreement shall include a counterpart in triplicate executed by each lessee seeking compulsory unitization. Lessees seeking compulsory unitization shall serve copies of the request and executed counterparts of the proposed unit agreement on the nonconsenting lessees.

(2) If the Director initiates compulsory unitization, the Director shall serve notice on all lessees of the proposed unit area with a copy of the proposed unit agreement or unitization plan and a statement of reasons for the proposed unitization.

(c)(1) The Director may not require compulsory unitization unless he has first provided reasonable notice and an opportunity for a hearing to all lessees of he proposed unit area. Any lessee of the proposed unit area may request a hearing within 30 days of service of notice by the Director or service of a request for compulsory unitization by a lessee.

(2) No hearing may be held pursuant to this paragraph until at lease 30 days written notice in advance of the hearing has been provided. The Director shall afford all lessees of the proposed unit area an opportunity to submit views orally and in writing and to question those seeking compulsory unitization. Adjudicatory procedures are not required, but the decision of the Director shall be based upon a record of the hearing including any written information made a part of the record. A party to a hearing may, at its own expense, cause a verbatim transcript to be made by a court reporter. If a verbatim transcript is made, three copies of the transcript shall be provided to the Director without charge within 10 days of the date of the hearing.

(d) The Director may issue an order or orders

that require or disapprove compulsory unitization or approve or disapprove voluntary unitization. Any such order shall include a statement of reasons. The final order of the Director or his delegate may be appealed in accordance with 30 CFR Part 290.

[29 FR 4563, Mar. 31, 1964; 34 FR 13547, Aug. 22, 1969; 38 FR 10001, Apr. 23, 1973; 45 FR 29285, May 2, 1980]

§ 250.52 Pooling or drilling agreements.

(a) Pooling or drilling agreements may be made between lessees for the purpose of:

(1) Utilizing a common drilling site to explore, develop, or produce adjacent or adjoining tracts;

(2) Permitting lessees or pipeline companies to enter into contracts involving a number of tracts sufficient to justify operations on a large scale for the exploration for and development, production, or transportation of oil and gas or other minerals, or to finance these operations; or

(3) For other purposes in the interest of conservation.

(b) A pooling or drilling agreement shall not be deemed to affect the requirements for drilling, production, or well reworking operations set out in the Act, the regulations, or the lease.

(c) Pooling and drilling agreements shall be filed with the Director, in conjunction with a development and production plan approved under 30 CFR 250.34-2.

[29 FR 4563, Mar. 31, 1964; 34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979; 45 FR 29285, May 2, 1980]

§ 250.53 Subsurface storage of oil or gas.

(a)(1) The Director may authorize the subsurface storage of oil or gas in the OCS when it can be shown that no undue interference with operations under existing leases will result.

(2) In each case, the authorization will provide for the payment of an adequate storage fee or rental on the stored oil or gas. When stored oil or gas is removed from storage in conjunction with oil or gas not previously produced, a royalty may be charged on the value or amount of stored oil or gas removed from storage in lieu of a fixed storage fee or rental. Any lease of an area used for the storage of oil or gas shall expire during the storage period unless oil or gas not previously produced on the lease is being produced in paying quantities or drilling or well reworking operations approved by the Secretary are underway.

(b) Applications for subsurface storage of oil or gas shall be filed with the Director, in triplicate, and shall include: the ownership of interests in the area involved; the parties involved, including lessees of other mineral interests; the storage fee, rental, or royalty offered to be paid for the right of storage; and all essential information showing the necessity for such storage. The storage agreement, signed by the parties involved, shall be submitted to the Director for approval, together with five copies for retention by the Department after approval.

[29 FR 4563, Mar. 31, 1964; 34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.54 Marking of equipment.

Whenever practicable, all materials, equipment, tools, containers, and items used on the OCS are to be properly color-coded, stamped, or labeled with the owner's identification, as approved or prescribed by the Director, prior to actual use. For oil and gas operations, this means that the owner's identification is to be placed upon all materials, cable, equipment, tools, containers, and other objects which could be freed and lost overboard from rigs, platforms, or supply vessels, and which are of sufficient size or are of such a nature that they could be expected to interfere with commercial fishing gear if lost overboard.

[44 FR 61892, Oct. 26, 1979]

§ 250.55 Flaring and venting of natural gas.

The lessee shall not flare or vent natural gas from any well without prior approval from the Director. Such approval will not be granted unless the Director finds that there is no practicable way to complete production of such gas, or the Director finds that flaring or venting is necessary to alleviate a temporary emergency situation or to conduct authorized testing or workover operations.

[44 FR 61892, Oct. 26, 1979]

§ 250.56 Fishermen's Contingency Fund.

Upon the establishment of an account under the Fishermen's Contingency Fund, pursuant to subsection 402(b) of the Act, for any area of the OCS, any holder of a lease, issued or maintained under the Act, for any tract in the area covered by the account, and any holder of an exploration permit or of an easement or right-of-way for the construction of a pipeline, in the area covered by the account, shall pay an amount specified by the Secretary of Commerce for the purpose of the establishment and maintenance of the account for the area. The Director shall collect the amount specified and deposit it in the Fund to the credit of the

appropriate area account.

[44 FR 61892, Oct. 26, 1979]

§ 250.57 Air Quality.

§ 250.57-1 Facilities described in a new or revised exploration plan or development and production plan.

(a) New Plans. All exploration plans and development plans deemed submitted under § 250.34-1(a) or § 250.34-2(a) on or after June 2, 1980, shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section and the lessee shall comply with the requirements of this section as necessary.

(b) Applicability of this Section to Existing Facilities. (1) The Director may review any exploration plan or development and production plan deemed submitted or approved prior to June 2, 1980, to determine whether any facility described in the plan should be subject to review under this section and has the potential to significantly affect the air quality of an onshore area. To make these decisions the Director shall consider the following: The distance of the facility from shore; the size of the facility; the number of sources planned for the facility and their operational status; and the air quality status of the onshore area.

(2) For a facility identified by the Director under paragraph (b)(1) of this section, the Director shall require the lessee to refer to the information required under § 250.34(a)(4) or § 250.34-3(b)(4) and to submit only that information required to make the necessary findings under paragraphs (d) through (i) of this section. The lessee shall submit this information within 120 days of the Director's determinaton or within a longer period of time at the discretion of the Director. The lessee shall comply with the requirements of § 250.57-1 as necessary.

(c) Revised facilities. All revised exploration plans and development and production plans which are deemed submitted under § 250.34-1(a) or § 250.34-2(a) on or after June 2, 1980, shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section. The lessee shall comply with the requirements of this section as necessary.

(d) Exemption Formulas. To determine whether a facility described in a new, modified, or revised exploration plan or development and production plan is exempt from further air quality review, the lessee shall use the highest annual total amount of emissions from the facility for each air pollutant calculated in § 250.34-3(a)(4)(ii)(A)(1) or § 250.34-3(b)(4)(ii)(A)(1) and compare these emissions to the emission exemption amount "E" for each air pollutant calculated using the following formulas: $E=3400^{2/3}$ for carbon monoxide (CO); and E=33.3D for total suspended particulates (TSP), sulfur dioxide (SO_2), nitrogen oxides (NO_x) and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the proposed facility from the closest onshore area of a State expressed in statute miles). If the amount of these projected emissions is less than or equal to the emission exemption amount "E" for the air pollutant, the facility is exempt for that air pollutant from further air quality review required by paragraphs (e) through (i) of this section.

(e) Significance Levels. For a facility not exempt under paragraph (d) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	[1]1	[1]5	.....	[1]25	....
TSP	[1]1	[1]5	.....	......	....
NO_3	[1]1	.....	....	......	....
CO	.....	.....	1500	.....	12,000

[1] $\mu g/m^3$

(f) Significance Determinations. (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance level determined under paragraph (e) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (d) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(g) Controls required. (1) The projected emissions of any air pollutant other than VOC from any facility, except a temporary facility, which significantly affect the quality of a nonattainment area shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(2) The projected emissions of any air pollutant other than VOC from any facility which significantly affect the air quality of an attainment or unclassifiable area shall be reduced through the application of BACT.

(i) Except for temporary facilities, the lessee also shall use an approved air quality model to determine whether the emissions of TSP or SO_2 that remain after the application of BACT cause the following maximum allowable increases over the baseline concentrations established in 40 CFR 52.21 to be exceeded in the attainment or unclassifiable area:

Air pollutant	Annual mean [1]	Maximum allowable increases (averaging times) 24-hour maximum	3-hour maximum
Class 1:			
TSP	[2]5	[2]10	......
SO_2	[2]2	[2]5	[2]25
Class 11:			
TSP	[2]19	[2]37	......
SO_2	[2]20	[2]91	[2]512
Class 111:			
TSP	[2]37	[2]75	......
SO_2	[2]40	[2]182	[2]700

[1] For TSP-geometric For SO_2-arithmetic
2 $\mu g/m^3$.

No concentration of an air pollutant shall exceed the concentration permitted under the national secondary ambient air quality standard, or the concentration permitted under the national primary air quality standard, whichever concentration is lowest for the air pollutant for the period of exposure. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one onshore location.

(ii) If the maximum allowable increases are exceeded, the lessee shall apply whatever additional emission controls are necessary to reduce or offset the remaining emissions of TSP or SO_2 so that concentrations in the onshore ambient air of an attainment or unclassifiable area do not exceed the maximum allowable increases.

(3)(i) The projected emissions of VOC from any facility, except a temporary facility, which significantly affect the onshore air quality of a nonattainment area shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(ii) The projected emissions of VOC from any facility which significantly affect the onshore air quality of an attainment area shall be reduced through the application of BACT.

(4)(i) If projected emissions from a facility significantly affect the onshore air quality of both a nonattainment and an attainment or unclassifiable area, the regulatory requirements applicable to projected emissions significantly affecting a nonattainment area shall apply.

(ii) If projected emissions from a facility significantly affect the onshore air quality of more than one class of attainment area, the lessee must reduce projected emissions to meet the maximum allowable increases specified for each class in paragraph (g)(2)(i) of this section.

(h) Controls Required On Temporary Facilities. The lessee shall apply BACT to reduce projected emissions of any air pollutant from a temporary facility which significantly affect the air quality of an onshore area of a State.

(i) Emission Offsets. When emission offsets are to be obtained, the lessee must demonstrate that: The offsets are equivalent in nature and quantity to the projected emissions that must be reduced after the application of BACT; a binding commitment exists between the lessee and the owner or owners of the source or sources; the appropriate air quality control jurisdiction has been notified of the need to revise the State Implementation Plan to include the information regarding the offsets; and the required offsets come from sources which affect the air quality of the area significantly affected by the lessee's OCS operations.

(j) Review of Facilities with Emissions Below the Exemption Amount. If, during the review of a new, modified, or revised exploration plan or development and production plan, the Director determines or an affected State submits information to the Director which demonstrates, in the judgment of the Director, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Director shall require the lessee to submit additional information to determine whether emission control measures are necessary. The lessee shall be given the opportunity to present information to the Director which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(k) Emission monitoring requirements. The lessee shall monitor, in a manner approved or

prescribed by the Director, emissions from the facility. The lessee shall submit this information, in a manner and form approved or prescribed by the Director, with the monthly report of operations prescribed under section 250.93 of this Part.

(1) Collection of meteorological data. The Director may require the lessee to collect for a period of time and in a manner approved or prescribed by the Director, and submit meteorological data from a facility.

[45 FR 15144, Mar. 7, 1980]

§ 250.57-2 Existing facilities.

(a) Process leading to review of an existing facility. (1) An affected State may request that the Director supply basic emission data from existing facilities when such data are needed for the updating of the State's emission inventory. In submitting the request, the State must demonstrate that similar offshore and onshore facilities in areas under the State's jurisdiction are included also in the emission inventory.

(2) The Director may require lessees of existing facilities to submit basic emission data to a State submitting a request under paragraph (a)(1) of this section.

(3) The State submitting a request under paragraph (a)(1) of this section may submit information from its emission inventory which indicates that emissions from existing facilities may be significantly affecting the air quality of the onshore area of the State. The lessee shall be given the opportunity to present information to the Director which demonstrates that the facility is not significantly affecting the air quality of the State.

(4) The Director shall evaluate the information submitted under paragraph (a)(3) of this section and shall determine, based on the basic emission data, available meteorological data, and the distance of the facility or facilities from the onshore area, whether any existing facility has the potential to significantly affect the air quality of the onshore area of the State.

(5) If the Director determines that no existing facility has the potential to significantly affect the air quality of the onshore area of the State submitting information under paragraph (a)(3) of this section, the Director shall notify the State of, and explain the reasons for, this finding.

(6) If the Director determines that an existing facility has the potential to significantly affect the air quality of an onshore area of the State submitting information under paragraph (a)(3) of this section, the Director shall require the lessee to refer to the information requirements under § 250.34-3(a)(4) or § 250.34-3(b)(4) and to submit only that information required to make the necessary findings under paragraphs (b) through (e) of this section. The lessee shall submit this information within 120 days of the Director's determination or within a longer period of time at the discretion of the Director. The lessee shall comply with the requirements of § 250.57-2 as necessary.

(b) Exemption formulas. To determine whether an existing facility is exempt from further air quality review, the lessee shall use the highest annual total amount of emissions from the facility for each air pollutant calculated in § 250.34-3(a)(4)(ii)(A)(1) or § 250.34-3(b)(4)(ii)(A) (1) and compare these emissions to the emission exemption amount "E" for each air pollutant calculated using the following formulas: $E=3400D^{2/3}$ for CO; and $E=33.3D$ for TSP, SO_2, NO_x, and VOC (where E is the emission exemption amount expressed in tons per year and D is the distance of the facility from the closest onshore area of a State expressed in statute miles). If the amount of projected emissions are less than or equal to the emission exemption amount "E" for the air pollutant, the facility is exempt for that air pollutant from further air quality review required under paragraphs (c) through (e) of this section.

(c) Significance levels. For a facility not exempt under paragraph (b) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	[1]1	[1]5	.....	[1]25	....
TSP	[2]1	[1]5	.....	.....	....
NO_x	[2]1	.....	.....	.....	....
CO	.....	.....	[1]500	......	[1]2,000

1 $\mu g/m^2$

(d) Significance determinations. (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance level determined under paragraph (c) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any

facility which is not exempt under paragraph (b) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(e) Controls required. (1) The projected emissions of any air pollutant which significantly affect the air quality of an onshore area shall be reduced through the application of BACT.

(2) The lessee shall submit a compliance schedule for the application of BACT. If it is necessary to cease operations to allow for the installation of emission controls, the lessee may apply for a suspension of operations under the provisions of § 250.12.

(f) Review of facilities with emissions below the exemption amount. If, during the review of the information required under paragraph (a)(6) of this section, the Director determines or an affected State submits information to the Director which demonstrates, in the judgment of the Director, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Director shall require the lessee to submit additional information to determine whether control measures are necessary. The lessee shall be given the opportunity to present information to the Director which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(g) Emission monitoring requirements. The lessee shall monitor, in a manner approved or prescribed by the Director, emissions from the facility following the installation of emission controls. The lessee shall submit this information, in a manner and form approved or prescribed by the Director, with the monthly report of operations prescribed under § 250.93.

(h) Collection of meteorological data. The Director may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Director, and submit meteorological data from a facility.

[45 FR 15144, Mar. 7, 1980]

MEASUREMENT OF PRODUCTION AND COMPUTATION OF ROYALTIES

§ 250.60 Measurement of oil.

The lessee shall measure, record, store, and transfer all oil produced in accordance with practices and procedures approved or prescribed by the Director. The quantity and quality of all oil production shall be determined and reported in accordance with the standard practices, procedures, and specifications generally used by the industry and approved by the Director.

[19 FR 2659, May 8, 1954; 34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.61 Measurement of gas.

The lessee shall measure all gas production, including gas vented or flared. In accordance with methods approved by the Director. The measured volumes shall be adjusted to a standard pressure base of 10 ounces above the atmospheric pressure of 14.4 pounds per square inch; to a standard temperature of 60 degrees Fahrenheit; and allow for deviation from Boyle's Law. If gas is being disposed of at a different pressure base, the Director may require that gas volumes be adjusted to conform to this base.

[19 FR 2659, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.63 Quantity basis for substances extracted from gas.

(a) The primary basis for computing the quantity of casinghead or natural gasoline, butane, propane, or other substances extracted from gas is the monthly net output of the plant at which the substances are manufactured. For purposes of this section, "net output" is the quantity of each substance that the plant produces.

(b)(1) When the net output of a plant is derived from the gas obtained from only one lease, the quantity of substances on which computations of royalty and net profit shares for the lease are based is the net output of the plant.

(2) When the net output of a substance from a plant is derived from gas obtained from several leases producing gas of uniform content, the proportion of net output of the substance allocable to each lease as a basis for computing royalty and net profit shares will be determined by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a substance from a plant is derived from gas obtained from several leases producing gas of diverse content, the proportion of net output of the substance allocable to each lease as a basis for computing royalty and net profit shares will be determined by multiplying the amount of gas delivered to the plant from the lease by the substance content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant.

[19 FR 2659, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.64 Value basis for computing royalties.

The value of production shall never be less than the fair market value. The value used in the computation of royalty shall be determined by the Director. In establishing the value, the Director shall consider: (a) The highest price paid for a part or for a majority of like-quality products produced from the field or area; (b) the price received by the lessee; (c) posted prices; (d) regulated prices; and (e) other relevant matters. Under no circumstances shall the value of production be less than the gross proceeds accruing to the lessee from the dispostion of produced substances or less than the value computed on the reasonable unit value established by the Secretary.

[19 FR 2659, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.65 Royalty on oil.

(a) The royalty on crude oil, including condensates separated from gas without the necessity of a manufacturing process, shall be a percentage of the value or amount of the crude oil produced from the leased area. The percentage shall be established by statute, regulation, or the provisions of the lease. No deduction shall be made for actual or theoretical transportation losses.

(b) Royalty is due on all oil which is (1) produced from a reservoir and sold by the lessee; (2) produced from a reservoir and used by the lessee for purposes of production from and operations upon the lease or unit area, or operations outside the lease or unit area, unless otherwise provided for in the lease; and (3) produced from a reservoir but lost, when such loss either was not specifically authorized or was avoidable. The royalty on oil may be based on production as products are moved from the lease. When conditions warrant, the Director may require royalty to be based on actual monthly production, including products remaining on the leased area. Evidence of all shipments shall be filed with the Director within 5 days, or longer periods when approved by the Director, after the oil has been shipped by pipeline or by other means of transportation. That evidence shall be signed by representatives of the lessee and by representatives of the purchaser or the transporter who witnessed the measurement reported. That evidence shall also note determinations of the gravity and temperature of the oil and the percentages of impurities contained in the oil.

[19 FR 2659, May 8, 1954; 34 FR 13547, Aug. 22, 1969; and 44 FR 61892, Oct. 26, 1979; 45 FR 81563, Dec. 11, 1980.

§ 250.66 Royalty on unprocessed gas.

Royalty is due on all gas which is (a) produced from a reservoir and sold by the lessee; (b) produced from a reservoir and used by the lessee for purposes of production from and operations upon the lease or unit area, or operations outside the lease or unit area, unless otherwise provided for in the lease; (c) produced from a reservoir but lost (vented or flared), when such loss either was not specifically authorized or was avoidable. Royalty is not due on gas or liquids produced from and reinjected to a reservoir, either within or outside the same lease or unit, until such time as they are finally produced from a reservoir. When gas is sold without processing for the recovery of constituent products the royalty thereon shall be a percentage, established by the terms of the lease, of the value or amount of the gas and constituent products. The value of wet gas and entrained liquids may be established by adjusting the value of the gas less entrained liquids using a British Thermal Unit (BTU) or other appropriate adjustment factor. The value shall not be less than that which would accrue by computing royalty in accordance with §§ 250.67(a) through (d) of this Part.

[19 FR 2659, May 8, 1954; and 44 FR 61892, Oct. 26, 1979; 45 FR 81563, Dec. 11, 1980]

§ 250.67 Royalty on processed gas and constituent products.

(a) When gas is processed for the recovery of constituent products, a royalty established by the terms of the lease will accrue on the value or amount of:

(1) All residue gas remaining after processing, and

(2) All natural gasoline, butane, propane, or other substances extracted from the gas. A reasonable allowance, determined by the Director and based upon regional plant practices and actual plant costs and other pertinent factors, may be made for the cost of processing and may be deducted from the royalty payment due on said constituent substances. However, the reasonable allowance shall not exceed two-thirds of the value of the substances extracted unless the Director determines that a greater allowance is in the national interest.

(b) Under no circumstances shall the amount of royalty on the residue gas and extracted substances be less than the amount which the Director determines would be payable if the gas had been sold without processing.

(c) In determining the value of natural gasoline, the volume of such gasoline shall be adjusted to a set standard, by a method approved or prescribed by the Director, when such adjustments are necessary to account for the

volumetric differences between natural gasolines of various specifications.

(d) No allowance shall be made for boosting residue gas or other expenses incidental to marketing.

(e) The lessee, with the approval of the Director, may establish a gross value per unit of 1,000 cubic feet of gas on the lease or at the wellhead for the purpose of computing royalty on gas processed for the recovery of constituent substances. When a gross value is so established, it shall be high enough to insure that the royalty due the United States is not less than that which would accrue by computing royalties in accordance with the provisions of (a) through (d) of this section.

[34 FR 13547, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.68 Commingling production.

Subject to such conditions as the Director may prescribe for the measurement and allocation of production, the Director may authorize the lessee to move production from the leased area to a central point for purposes of treating, measuring, and storing. In moving such production, the lessee may commingle the production from different wells, leased areas, pools, and fields which it operates with production from other operators. The central point may be at any convenient place approved or prescribed by the Director.

[19 FR 2660, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.69 Measurement of sulphur.

For the purpose of computing royalty, the measurement of sulphur shall be on such basis and shall conform to such standards as the Director may approve or prescribe.

[19 FR 2660, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

INVESTIGATIONS

§ 250.70 Reports and investigations of apparent violations.

Any person may report an apparent violation or failure to comply with any provisions of the Act, or any provision of a lease, license, or permit issued pursuant to the Act, or any provision of any regulation or order issued under the Act. When a report of an apparent violation has been received, or when an apparent violation has been detected by Geological Survey personnel, the matter will be investigated and the party will be advised of the matter under investigation.

[44 FR 61892, Oct. 26, 1979]

§ 250.71 Reports on Investigations.

(a) Reports of the results of any investigation conducted by the Geological Survey, or received from any other Agency, which indicate that a violation under the Act may have occurred, must be forwarded to the official of the Geological Survey designated by the Director (referred to in this and subsequent sections as the "Director's designee"). The Director's designee shall review the reports.

(b) If the Director's designee determines that there is insufficient evidence to indicate that a violation probably occurred, the case will be returned to the originating office for further investigation or the case will be closed. The case will be closed when: (1) the Director's designee's review establishes that a violation did not occur; (2) the violator cannot be identified; or (3) although there is sufficient evidence to indicate that a violation occurred, there appears to be little likelihood of discovering additional relevant facts to justify further investigation.

(c) If the Director's designee determines that there is sufficient evidence to indicate that a violation probably occurred, a case file will be prepared and forwarded to a Reviewing Officer for further action.

[44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.72 Knowing and willful violations.

When the Director's designee determines that there is sufficient evidence to indicate that a knowing and willful violation may have occurred, the Director's designee will prepare a case file and forward it through the office of the Solicitor to the Department of Justice.

[44 FR 61892, Oct. 26, 1979]

REMEDIES AND PENALTIES

§ 250.80 Remedies and penalties.

§ 250.80-1 Remedies.

(a)(1) The Director shall designate one or more senior employees of the Conservation Division, U.S. Geological Survey, to act as Reviewing Officer(s).

(2) The Reviewing Officer shall have no other responsibility, direct or, supervisory, for the investigation or prosecution of cases.

(3) The Reviewing Officer shall decide each case on the basis of the evidence in the case file and shall have no prior connection with the case. The Reviewing Officer will be solely

responsible for the decision made in each case.

(4) The Reviewing Officer is authorized to administer oaths and issue subpoenas, to the extent provided by the Act, necessary to conduct a hearing.

(5) The Reviewing Officer is authorized to assess civil penalties and, when appropriate, to recommend the initiation of criminal proceedings.

(b)(1) When a case file is received, the Reviewing Officer shall make a preliminary examination of the material submitted.

(2) If, on the basis of the preliminary examination of the evidence in a case file, the Reviewing Officer determines that there is insufficient evidence or that there is any other reason which would make further action inappropriate, the Reviewing Officer shall return the case to the Director's designee with a written statement indicating the reason for this action. The Director's designee may close the case or cause a further investigation of the alleged violation to be conducted with a view toward resubmittal of the case to the Reviewing Officer.

(3) If, on the basis of the preliminary examination of the case file, the Reviewing Officer confirms that the evidence indicates that a violation may have occurred, the Reviewing Officer shall notify the party, in writing, of:

(i) The alleged violation citing the applicable provision of the Act, or the applicable term of a lease, license, or permit issued pursuant to the Act, or the applicable provision of a regulation or order issued under the Act upon which the action is based;

(ii) The general nature of the procedures that will be followed for evaluating the party's responsibility for the alleged violation and for assessing and collecting a penalty should it be determined that the party is responsible for the violation;

(iii) The amount of penalty that appears would be appropriate in the event it is determined that the party is responsible for the alleged violation, based upon the material then available to the Reviewing Officer.

(iv) The party's right to examine the material in the case file and to have a copy of all written documents provided upon request, except those which would, in a civil proceeding, disclose or lead to the disclosure of a confidential informant; and

(v) The fact that, subject to the provisions of paragraph (d)(2) of this section, the party has a right to a hearing before the Reviewing Officer prior to any finding of fact regarding the alleged violation.

(4) If, at any time, the Reviewing Officer determines that the addition of another person to the proceedings is necessary or desirable, the Reviewing Officer shall notify and provide the additional party with the information described in paragraph (b)(3) of this section.

(c) A party has the right to be represented by counsel, qualified to practice before the Department under 43 CFR Part 1, at all stages of the proceeding. After receiving notification that a party is represented by counsel, the Reviewing Officer shall direct all further communications to the counsel.

(d)(1) Within 30 working days after receipt of a notice pursuant to paragraph (b)(3) of this section, the party, or counsel for the party, may; (i) request a hearing before the Reviewing Officer; (ii) provide any written evidence and arguments in lieu of a hearing; or (iii) pay the amount specified in the notice. A request for a hearing before the Reviewing Officer must be in writing, and must specify the particular issues which are in dispute. Failure to specify a nonjurisdictional issue will preclude its consideration.

(2) The right to a hearing before the Reviewing Officer shall be waived if the party does not submit a request for a hearing to the Reviewing Officer within 30 working days after receiving the notice described in paragraph (b)(3) of this section unless the Reviewing Officer grants the party additional time to submit a request for a hearing.

(3) The Reviewing Officer shall promptly schedule all hearings which are requested. The Reviewing Officer shall grant any delays or continuances which the Reviewing Officer determines to be necessary or desirable in the interest of obtaining a fair resolution of the case.

(4) A party requesting a hearing before a Reviewing Officer may amend the specification of the nonjurisdictional issues in dispute at any time up to 10 working days before the scheduled hearing. Nonjurisdictional issues raised less than 10 working days before the scheduled hearing date may be presented only at the discretion of the Reviewing Officer.

(e) Prior to a hearing, the party or counsel for the party may examine all the written evidence in the case file, except material that would, in a civil proceeding, disclose or lead to the disclosure of the identity of a confidential informant. Other evidence or material, such as blueprints, sound or videotapes, oil samples, and photographs may also be examined in the Reviewing Officer's office. However, the Reviewing Officer may provide for examination or testing of the evidence at other locations, if there are adequate safeguards to prevent loss or tampering with the evidence.

(f)(1) In addition to information treated as confidential under (d) of this section, confidential treatment shall be accorded to all or a portion of any document at the request of the person supplying the information if the information is:

(i) Confidential financial information, trade secrets, or other material exempt from

disclosure under the Freedom of Information Act (5 U.S.C.552);

(ii) Information required to be held in confidence by the regulations in this Chapter II or 18 U.S.C. 1905; or

(iii) Information that is otherwise exempt by law from disclosure.

(2) The person desiring confidential treatment for information must submit a written request to the Reviewing Officer stating the reasons justifying nondisclosure. Failure to make a request at the time a document is submitted may result in the document being considered as nonconfidential and subject to release.

(3) Confidential material will not be considered by the Reviewing Officer in reaching a decision unless:

(i) It has been furnished by a party, or

(ii) It has been furnished pursuant to a subpoena.

(g)(1) When a hearing is requested in accordance with (d)(1) of this section, the hearing will be held in the office of the Reviewing Officer, or at some other convenient location selected or approved by the Reviewing Officer.

(2) A party requesting a hearing in accordance with (d)(1) of this section may request that the Director's designee transfer the case to another Reviewing Officer, or that the hearing be held at a location other than the office of the Reviewing Officer. The request must be in writing and state the reasons why the requested action is necessary or desirable. Action on a request for the transfer of a case to a different Reviewing Officer is subject to the discretion of the Director's designee.

(h)(1) The testimony of any witness may be presented either through a personal appearance or through a written statement. The Reviewing Officer, upon request of a party, may assist in obtaining the testimony of a witness by personal appearance. A request for such assistance must be in writing and must state the reasons why a written statement by the witness would be inadequate, the issue or issues to which the testimony would be relevant, and the substance of the expected testimony. If the Reviewing Officer determines that the personal appearance of the witness will materially aid in the decision on the case, the Reviewing Officer will seek to obtain the personal appearance of the witness.

(i)(A) The Reviewing Officer is authorized to issue subpoenas requiring the attendance of witnesses at hearings or for the taking of depositions.

(B) Subpoenas will be issued in a manner and format approved by the Director.

(C) The application for a subpoena shall be filed in the office of the Reviewing Officer.

(D) The original subpoena, bearing a certificate of service, shall be filed with the Reviewing Officer.

(E) A witness may be required to attend a hearing or deposition at a place not more than 100 miles from the place of service.

(ii)(A) Witnesses subpoenaed by any party shall be paid the same fees and mileage paid for similar services in the District Courts of the United States. The witness fees and mileage shall be paid by the party at whose insistence the witness appears.

(B) Any witness who attends a hearing or the taking of a deposition at the request of the party, without having been subpoenaed to do so, shall be entitled to the same mileage and attendance fees paid to a subpoenaed witness. The witness fees and mileage shall be paid by the party at whose insistence the witness appears. The provisions of this paragraph are not applicable to Federal Government employees who are called as witnesses by the Federal Government.

(2) In cases where an individual cannot be required to appear as a witness, the Reviewing Officer may move the hearing to the location of the desired witness, accept a written statement, or accept a stipulation in lieu of testimony.

(i)(1) The Reviewing Officer must conduct a fair and impartial proceeding in which the party is given a full opportunity to be heard.

(i) At the outset of the hearing, the Reviewing Officer shall insure that the party is aware of the nature of the proceedings and of the alleged violation.

(ii) Material in the case file which is pertinent to issues, shall be presented. The party has the right to respond to or rebut this material. The party may offer any facts, statements, explanation, documents, sworn or unsworn testimony, or other exculpatory items which bear on the issues or which may be relevant to the amount of the penalty to be assessed if the party is found to be guilty of the alleged violation. The Reviewing Officer may require the authentication of any written exhibit or statement.

(iii) After the evidence in the case file has been presented, the party may present argument on the issues in the case. The party may request an opportunity to submit additional written testimony for consideration by the Reviewing Officer. The Reviewing Officer shall allow a reasonable time for submission of additional written testimony and shall specify the date by which it must be received. If the statement is not received within the time prescribed or within the limits of any extension of time granted by the Reviewing Officer, the Reviewing Officer shall render a decision on the basis of the record in the case file.

(iv) At the close of the party's presentation of evidence, the Reviewing Officer shall allow the introduction of rebuttal evidence. The Reviewing Officer shall allow the party an opportunity to respond to any rebuttal evidence

that is submitted.

(v) The Reviewing Officer may take notice of matters which are subject to a high degree of indisputability and are commonly known in the community or are ascertainable from readily available sources of known accuracy. Prior to taking notice of a matter, the Reviewing Officer shall give the party an opportunity to show why notice should not be taken. In any case in which such notice is taken, the Reviewing Officer shall place in the record a written statement on the matters to which notice was taken and the basis for taking such notice. The Reviewing Officer's statement shall indicate that the party consented to notice being taken or shall include a summary of the party's objections to notice being taken of a specific matter.

(2) In reviewing evidence, the Reviewing Officer is not bound by strict rules of evidence. In evaluating the evidence presented, the Reviewing Officer shall give due consideration to the reliability and relevance of each item of evidence.

(j)(1) A verbatim transcript of hearings before a Reviewing Officer will not normally be prepared. The Reviewing Officer shall prepare notes on the material and points raised by the party in sufficient detail to permit a full and fair review and resolution of the case, should it be appealed.

(2) A party may, at its own expense, cause a verbatim transcript to be made by a court reporter. If a verbatim transcript is made, and the Reviewing Officer's decision is appealed, the party shall submit two copies of the verbatim transcript with the appeal to the Director's designee. The verbatim transcript will be included in the case record.

(k)(1) The decision called for in subparagraph (j)(1)(iii) of this section shall be issued in writing, and shall include:

(i) The Reviewing Officer's conclusions and the basis for those conclusions; and

(ii) The appropriate rule, order, sanction, relief, or denial thereof. Any decision to assess a penalty shall be based upon substantial evidence in the record. If the Reviewing Officer finds that there is not substantial evidence in the record establishing that the alleged violation probably occurred, the Reviewing Officer shall dismiss the case and remand it to the Director's designee. A dismissal is without prejudice to the Director's designee's right to refile the case and have it reheard if additional evidence is obtained. A dismissal following a rehearing is final and with prejudice.

(2) In assessing a penalty, the Reviewing Officer shall review the record of any prior violations by the party. The Reviewing Officer's decision shall contain a statement advising the party of the right to an administrative appeal to the Director pursuant to Part 290 of this Chapter. The party shall be advised that a failure to submit an appeal within the prescribed time will bar its consideration, and that failure to appeal on the basis of a particular issue will constitute a waiver of that issue in any subsequent proceeding. An appeal from any interim ruling of the Reviewing Officer shall be reserved and considered only at the time of and as part of an appeal from the Reviewing Officer's final decision.

(l)(1) Any appeal from the decision of the Reviewing Officer and any supporting argument must be submitted by a party to the Reviewing Officer within 30 days from the date of receipt of the decision. The appellant shall provide copies of the notice of appeal and supporting brief to the Director. The only issues which will be considered on appeal are those issues specified in the notice of appeal which were properly raised before the Reviewing Officer and jurisdictional questions.

(2) The failure to file a notice of appeal within the prescribed time limit shall result in the action of the Reviewing Officer becoming the final action of the U.S. Department of the Interior in the case.

(m)(1) The appeal of a decision of the Reviewing Officer and supporting brief, and any comments which the Reviewing Officer desires to submit regarding the appeal must be forwarded to the Director within 30 working days following receipt of the notice of appeal and any supporting brief. The Reviewing Officer shall have a longer period of time to submit comments regarding an appeal when the appellant requests that the Director grant additional time for submitting supporting arguments. The Reviewing Officer shall provide the appellant with a copy of all comments submitted to the Director.

(2)(i) The Director may affirm, reverse, or modify the Reviewing Officer's decision, or remand the case for new or additional proceedings.

(ii) The Director may increase, remit, mitigate, or suspend, in whole or in part, any penalty assessed by the Reviewing Officer.

(iii) When the action of the Director includes the increase, remission, mitigation, or suspension, in whole or in part, of a penalty assessed by the Reviewing Officer, the appellant and the Reviewing Officer shall be advised of any conditions placed upon that action.

(iv) The Director shall issue a written decision in each case. Copies of the Director's decision are to be provided to the appellant and the Reviewing Officer.

(v) In the absence of an appeal from the Director's decision pursuant to 30 CFR Part 290, the Director's decision on an appeal shall be final.

(n)(1) At any time prior to final Geological Survey action in a civil penalty case, a party may petition to reopen the hearing on the basis of newly discovered evidence.

(2) Petitions to reopen a case must be in

writing. Petitions shall describe the newly found evidence and state why the evidence would probably produce a different result favorable to the petitioner. The petitioner must state whether the evidence was known to the petitioner at the time of the hearing and, if not, why the newly found evidence could not have been discovered during the original proceedings. The party must submit the petition to the Reviewing Officer and provide a copy to the Director's designee.

(3) The Director's designee may file comments in opposition to the petition. If the Director's designee files comments, a copy of the comments shall be provided to the petitioner.

(4) The Reviewing Officer will consider a petition to reopen a case unless an appeal has been filed or the time period for filing an appeal has expired and no appeal was filed. In those cases where an appeal has been timely filed, a petition to reopen a case will be considered by the Director.

(5) The Reviewing Officer's decision on a petition to reopen a case will be decided on the basis of the current case record, the contents of the petition, and the comments, if any, submitted by the Director's designee pursuant to paragraph (n)(3) of this section.

(6) A petition to reopen a case will be granted only when the Reviewing Officer determines that newly found evidence, that would have a direct and material bearing on the issue(s) of the case, is described in the petition and when the petitioner provides a valid explanation as to why the new evidence was not and could not have been produced previously. A decision on a petition to reopen a case shall be rendered in writing.

(7) The denial of a petition to reopen a case shall be final and may not be appealed in an action separate from the appeal of the case pursuant to subsection (m) of this section or Part 290 of this Chapter.

(o)(1) The Director's designee shall collect civil penalties assessed by a Reviewing Officer, the Director, or the Department of the Interior's Board of Land Appeals.

(2) Payment of a civil penalty may be made by check or postal money order payable to the U.S. Geological Survey.

(3) Within 30 calendar days after the issuance of the Reviewing Officer's decision in a case, the party must submit payment of any assessed penalty to the Director's designee. Payment is to be made even though an appeal is pending. Failure to make timely payment will result in the collection of the amount assessed plus interest from the date of assessment until the date of payment. Interest shall be calculated at the average of the highest rate for commercial and finance company paper of maturities of 180 days or less obtaining on each of the days included within the period for which interest is due. Such failure may also result in the initiation of additional enforcement proceedings, including, if appropriate, cancellation of the lease or permit under § 250.12 of this Part.

[19 FR 2660, May 8, 1954; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.80-2 Penalties.

(a)(1) Pursuant to subsection 24(b) of the Act, any person who fails to comply with any provision of the Act or any term of a lease, license, or permit issued pursuant to the Act, or any provision of any regulation or order issued under the Act, shall be liable for a civil penalty of not more than $10,000 for each day of continuance of such failure. The Director may assess, collect, and compromise a civil penalty after notice of the failure and the passage of a reasonable period of time to allow for corrective action. No penalty shall be assessed until the person charged with a violation has been given an opportunity for a hearing pursuant to § 250.80 of this Part.

(2)(i) Pursuant to subsection 24(c) of the Act, the penalties set forth in section 250.80-2(a)(2)(ii) will be assessed on any party, upon conviction, who knowingly and willfully:

(A) Violates any provision of the Act, any term of a lease, license, or permit issued pursuant to the Act, or any regulation or order issued under the authority of the Act designed to protect health, safety, and environment, or to conserve natural resources;

(B) Makes any false statement, representation, or certification in any application, record, report, or other document filed or required to be maintained under the Act;

(C) Falsifies, tampers with, or renders inaccurate any monitoring device or method of record required to be maintained under the Act; or

(D) Reveals any information and data required to be kept confidential by the Act.

(ii) Any person convicted of a violation described in subparagraphs (a)(2)(i)(A), (B), (C), or (D) shall be punished by a fine of not more than $100,000 or by imprisonment of not more than 10 years, or both.

(iii) For each day that a violation described under subparagraph (a)(2)(i)(A) of this section continues, or for each day that any monitoring device or data recorder remains inoperative or inaccurate because of any activity described in subparagraph (a)(2)(i)(C) of this section, there shall be a separate violation.

(3) Whenever a corporation or other entity is subject to prosecution for a violaion described under subparagraphs (a)(2)(i)(A), (B), (C), or (D) of this section, any officer or agent of such corporation or entity who knowingly and willfully authorized, ordered, or carried out the prescribed activity shall be subject to the

same fines or imprisonment, or both, as provided for under subparagraph (a)(2)(ii) of this section.

(4)(i) If a violation of law or regulation is subject to both a civil and a criminal penalty, the Director's designee is authorized to decide whether to institute civil penalty proceedings or to recommend referral of the case through the Office of the Solicitor to the Department of Justice for the institution of an enforcement action in the appropriate Federal Court, or both.

(ii) The Director's designee shall decide, within 30 working days of an apparent violation or within 30 working days of a decision to refile or resubmit a case, whether the apparent violation will be referred through the Office of the Solicitor to the Department of Justice for investigaion into whether criminal proceedings should be initiated. When a case is referred through the Office of the Solicitor to the Department of Justice, the Director's designee shall advise the alleged violator of that action and shall warn the alleged violator that, regardless of the outcome of any criminal proceedings, civil penalty proceedings may be initiated.

(5) A decision by the Department of Justice not to institute criminal proceedings in the appropriate Federal Court shall not preclude the Director's designee from initiating or continuing the conduct of civil penalty proceedings in the case.

(6) The remedies and penalties prescribed in this section shall be concurrent and cumulative, and the exercise of one shall not preclude the exercise of the others. Further, the remedies and penalties prescribed in this section shall be in addition to any other remedies and penalties afforded by any other law or regulation.

[19 FR 2660, May 8, 1954; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980; 45 FR 37818, June 5, 1980]

§ 250.81 Appeals.

OCS Orders, other orders, or decisions issued under the regulations in this Part may be appealed in accordance with the provisions of Part 290 of this Chapter. The filing of an appeal shall not suspend the requirement for compliance with an order or decision.

[38 FR 10001, Apr. 23, 1973; 44 FR 61892, Oct. 26, 1979]

§ 250.82 Judicial review.

Nothing contained in this Part shall be construed to prevent any interested party from seeking judicial review as authorized by law.

[19 FR 2660, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

REPORTS TO BE MADE BY ALL LESSEES (INCLUDING OPERATORS)

§ 250.90 General requirements.

Information, required to be submitted pursuant to the regulations in this Part, shall be furnished in the manner and form prescribed in the regulations in this Part or as ordered by the Director. Copies of forms can be obtained from the Director and must be filled out completely and filed punctually with the Director.

[19 FR 2660, May 8, 1954; 44 FR 61892, Oct. 26, 1979]

§ 250.92 Sundry notices and reports on wells.

(a) All notices of the lessee's intention to fracture, treat, acidize, repair, multiple complete, abandon, change plans, or to engage in similar activities, and all subsequent reports pertaining to such operations shall be submitted on Form 9-331 in accordance with paragraph 250.38(b)(1) of this Part. The Director will advise the lessee concerning the number of copies of Form 9-331 that are to be submitted. Prior to commencing such operations, written approval must be received from the Director

(b) Form 9-331 shall contain:

(1) A detailed statement of the proposed work for repairing (other than work incidental to ordinary well operation), acidizing, or stimulating production by other methods, perforating, sidetracking, squeezing with mud or cement, or commencing any operations (other than those covered by § 250.36 of this Part) that will materially change the approved program for drilling a well or will alter the condition of a completed well.

(2) A detailed report of all the work done and the results obtained. The report shall set forth the amount and rate of production of oil, gas, and water before and after the completion of work and shall include a complete statement describing the methods used and giving the dates on which the work was accomplished.

(3) A detailed statement of the proposed work for abandonment of any well. For all wells, the statement shall describe the proposed work (including, by depths, the kind, location, and length of plugs), and plans for mudding, cementing, shooting, testing, and removing casing, and other pertinent information. The statement as to a producible well shall set forth the reasons for abandonment and the amount and date of last production.

(4) A detailed report describing the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in the plugging and the location and extent, by depths, of casing left

in the well, and the volume of mud fluid used. If an attempt was made to cut and pull any casing string, a description of the methods used and results obtained must be included.

(c) This reporting requirement has been approved by the Office of Management and Budget in accordance with the Federal Reports Act of 1942 (42-R1424).

[34 FR 13548, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.93 Monthly report of operations.

(a) A separate report of operations for each lease must be made on Form 9-152 for each calendar month, beginning with the month in which drilling operations are commenced, and must be filed in duplicate with the Director on or before the 20th day of the succeeding month, unless an extension of time for the filing of the report is granted by the Director. The report must be submitted each month until the lease is terminated or until the Director authorizes discontinuance of the report.

(b) The report on Form 9-152 shall disclose accurately:

(1) All operations conducted on each well during each month;

(2) The status of operations on the last day of the month; and

(3) A general summary of the status of operations on the leased area.

(c) The report shall show for each calendar month:

(1) Each well, listed separately;

(2) The number of days each active well produced, the nature of production (whether oil or gas) and the number of days each input well was used for injection service;

(3) The quantity of oil, condensate, gas, and water produced;

(4) The total depth of each active or suspended well;

(5) The name, character, and depth of each formation drilled during the month, the date each depth was reached, (special attention should be given to the names and depths of important formation changes and the contents of formations), and the dates and results of any tests, such as production or water shutoff;

(6) The amount, grade, and size of any casing run since the last report; and

(7) The date and reason for every shutdown and all other noteworthy information on operations not specifically provided for in the form.

(d) If no runs or sales were made during the calendar month, this must be stated in the report.

(e) This reporting requirement has been approved by the Office of Management and Budget in accordance with the Federal Reports Act of 1942 (42-R1236).

[19 FR 2661, May 8, 1954; 44 FR 61892, Oct. 26, 1979; 45 FR 20465, Mar. 28, 1980]

§ 250.94 Statement of oil and gas runs and royalties.

(a) When required by the Director, a monthly report shall be submitted on Form 9-153, showing: each run of oil; all transfers of gas and other lease products; and the royalty accruing therefrom to the lessor. Form 9-153 shall be submitted on or before the last day of the calendar month which follows the calendar month in which the production is obtained.

(b) This reporting requirement has been approved by the Office of Management and Budget in accordance with the Federal Reports Act of 1942 (42-R1237).

[19 FR 2661, May 8, 1954; 34 FR 13548, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.95 Well completion or recompletion report and log.

(a) All reports and logs of well completions or recompletions shall be submitted in duplicate on or attached to Form 9-330 in accordance with paragraph 250.38(b)(1) of this Part. The form shall contain: a complete and accurate log and report of all operations on the well as specified on the form; geologic markers and all important zones of porosity and contents thereof; cored intervals and all drill-stem tests including depth interval tested, cushion used, and the time the tool was open; flowing and shut-in pressures; and recoveries. Duplicate copies of logs compiled for geologic information from core or formation samples shall be filed in addition to the regular log. If not previously furnished, duplicate copies of composites of multiple runs of all well bore surveys, including electric, radioactive, and other logs, temperature surveys, and directional surveys shall be attached. (Such copies are in addition to field prints filed pursuant to § 250.38(b)(3) of this Part.)

(b) This reporting requirement has been approved by the Office of Management and Budget in accordance with the Federal Reports Act of 1942 (42-R0355).

[34 FR 13548, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

§ 250.96 Special forms or reports.

When special forms or reports, other than those referred to in the regulations in this Part, are deemed necessary, instructions for the filing of such forms or reports will be given by the Director.

[19 FR 2661, May 8, 1954; 34 FR 13548, Aug. 22, 1969; 44 FR 61892, Oct. 26, 1979]

6. Preamble, Model Unit Agreement Form, 45 FR 43256, June 26, 1980.

Geological Survey

Model Unit Agreement for Use in the Unitization of Operations Under Outer Continental Shelf (OCS) Oil and Gas Leases

AGENCY: U.S. Department of the Interior, Geological Survey.

ACTION: Announcement of Model Unit Agreement for use in the Unitization of Operations Under Outer Continental Shelf (OCS) Oil and Gas Leases.

SUMMARY: The Department of the Interior has developed a Model Unit Agreement for use in the unitization of operations under OCS oil and gas leases. A proposed Model Unit Agreement was published in the Federal Register on August 10, 1979 (44 FR 47169), together with an invitation for interested parties to submit their written comments and recommendations. The Model Unit Agreement published today incorporates modifications which are based on the comments and recommendations which were received. The Model Unit Agreement also reflects the Department of the Interior's policy to assure prompt and efficient exploration and development of OCS oil and gas leases. This Model Unit Agreement is to be used in conjunction with the regulations in §§ 250.50, 250.51, and 250.52 that were published as Final Rule in the May 2, 1980, Federal Register (45 FR 29280). This Model Unit Agreement will serve the same purpose for the unitization of OCS oil and gas leases that the Model Unit Agreement found in 30 CFR § 226.12 serves for onshore oil and gas leases.

FOR FURTHER INFORMATION CONTACT:

Gerald D. Rhodes, Conservation Division, U.S. Geological Survey, National Center, Mail Stop 640, 12201 Sunrise Valley Drive, Reston, Virginia 22092; phone 703/860-7531.

PRINCIPAL AUTHORS: W. P. Elliott, Office of the Solicitor; David Page, Office of the Assistant Secretary--Energy and Minerals; and Gerald D. Rhodes, U. S. Geological Survey.

ADDRESSES: A copy of the Model Unit Agreement may be obtained from the following offices of the Geological Survey:

Deputy Division Chief, Offshore Minerals Regulation, Conservation Division, U.S. Geological Survey, National Center--Mail Stop 640, 12201 Sunrise Valley Drive, Reston, Virginia 22092.

Conservation Manager, Alaska Region, U.S. Geological Survey, 800 "A" Street, Suite 109, Anchorage, Alaska 99501.

Conservation Manager, Pacific OCS Region, U.S. Geological Survey, 1340 West Sixth Street, Room 160, Los Angeles, California 90017.

Conservation Manager, Eastern Region, U.S. Geological Survey, 1725 K Street NW., Suite 204, Washington, D.C. 20244.

Conservation Manager, Gulf of Mexico OCS Region, U.S. Geological Survey, 336 Imperial Office Building, P.O. Box 7944, Metairie, Louisiana 70010.

SUPPLEMENTARY INFORMATION

BACKGROUND

In April 1978 the Department of the Interior initiated a review of the past and current criteria and procedures used in the unitization of operations under OCS oil and gas leases. The results of that review and enactment of the OCS Lands Act Amendments of 1978 (43 U.S.C. 1334) led to (1) the proposed revisions of 30 CFR 250.50 and 250.51 that were published August 10, 1979 (44 FR 47109), and (2) the development of the proposed Model Unit Agreement that was also published in the Federal Register on August 10, 1979 (44 FR 47169).

COMMENTS

A total of 21 sets of comments and recommendations were submitted in response to the invitation contained in the Notice of the development of a Model Unit Agreement published August 10, 1979. All of the comments and recommendations that were received came from oil and gas companies and trade organizations.

DIFFERENCES BETWEEN THE MODEL UNIT AGREEMENT AND THE PROPOSED MODEL UNIT AGREEMENT.

The differences between the provisions of the Model Unit Agreement published by this Notice and the provisions of the proposed Model Unit Agreement published August 10, 1979, are the results of the Department's efforts: (1) To incorporate the comments received; (2) to make the provisions of the Model Unit Agreement more clear; and (3) to assure conformance with the OCS Lands Act, as amended (herein referred to as the "Act"), and the implementing regulation §§ 250.50 and 250.51.

DISCUSSION OF MAJOR COMMENTS:

1. Extend Comment Period and Hold Informal Meetings.

A number of respondents suggested that the comment period for the Model Unit Agreement and the proposed regulation be extended and that informal meetings be held to afford industry representatives and other representatives an opportunity to participate in a free exchange of views with representatives of the Department of the Interior. This suggestion was not adopted. Anyone interested in an opportunity to participate in a discussion of the proposed Model Unit Agreement and the proposed regulation with representatives of the Department of the Interior was free to request such a meeting during the comment period set out in the Federal Register Notice of August 10, 1979. The Offshore Operators Committee requested and obtained such a meeting in order to present its comments on the proposed Model Unit Agreement and the proposed rule.

2. Develop a Separate Model Unit Agreement for the Three Major Categories Under Which the Unitization of Operations may be Classified.

A number of respondents suggested that a separate Model Unit Agreement be developed for each of the three major categories of unitized activities, i.e., that a separate Model Unit Agreement be developed for use when there is:

(a) A voluntary unitization of operations (all lessees execute a unit agreement);

(b) Unitization of operations is ordered by the Director on the Director's initiative; or

(c) Unitization of operations is ordered by the Director at the request of one or more (but less than all) lessees.

This suggestion has not been adopted. The Model Unit Agreement published today is sufficiently flexible to be adapted to the needs of each of the variety of circumstances surrounding the formulation of an agreement to govern unitized operations under portions of two or more OCS oil and gas leases. As experience is gained during the implementation of the Final Rule that becomes effective June 30, 1980, consideration will be given to the development of special provisions to meet demonstrated special needs for one or more of the three major categories of units.

3. Identify the Nature of the Area Unitized.

A number of respondents questioned whether the Model Unit Agreement envisioned a unit area which is 2-dimensional in nature or one that is 3-dimensional in nature, i.e., limited by depth, and suggested that the Final Rule and Model Unit Agreement clarify the nature of a unit area. The Final Rule and the Model Unit Agreement are designed to permit the unit area to be viewed as being limited by depth. The depth limitation, if any, placed on a specific unit area will be determined at the time that a unit agreement is being developed. In the event there is a question regarding whether a specific unit area is limited by depth, the approving officer will indicate in the approval document whether the unit area is limited by depth.

4. Use of Different Bases for Allocating Production from Different Reservoirs.

One respondent described the proposed Model Unit Agreement as inadequate because the respondent felt that the proposed Model Unit Agreement did not allow for a different basis of participation for each separate reservoir. The Model Unit Agreement published today provides for the allocation of oil and gas produced under the unit agreement on the basis of the number of acres of the lease or part of a lease in the unit area or as may be determined on the basis of the estimated recoverable volumes of oil or gas, or both, originally in place under each lease computed on the basis of reservoir characteristics. Where the characteristics of separate reservoirs under a unit area are different, the allocation of production from different reservoirs should reflect the differences in reservoir characteristics.

5. Execution of the Unit Operating Agreement.

A number of respondents indicated that they believed that the execution of a unit operating agreement prior to the submission of an executed unit agreement is an impractical expectation. Similarly, those respondents objected to having to submit amendments to unit operating agreements at least 30 days prior to their effective date. Both suggestions have been rejected. With rare exception, the Department of the Interior has required that executed unit agreements be accompanied by executed unit operating agreements. In order for an interest to be made subject to the unit agreement, the corresponding working interest must be subject to the unit operating agreement. Similarly, since changes in the unit operating agreements may result in a change in emphasis on exploration, development, and production activities, the Department insists that it be fully apprised of those possible changes in emphasis prior to their occurrence.

6. Expense for Unit Operator's Appearances.

One respondent objected to the unit agreement authorizing the unit operator to charge the expense of appearances to the other parties to a unit agreement and suggested that expenses

for appearances by the unit operator should be subject to negotiation and should be part of the unit operating agreement. This suggestion has been rejected. Appearances are a normal function of the unit operator as unit operator and the expense for appearances are properly charged as normal unit operating expense. Any nonoperating interest owner is free to make an appearance for the purpose of presenting an opposing or supporting view. However, the appearance of the nonoperating interest owner is not a normal unit operating function and, thus, is not chargeable as a unit operating expense. A nonoperator wishing to present an opposing view to that of the unit operator has the right to make such a presentation at its own expense.

7. Net Profit and Work Commitment Obligations.

One respondent recommended that the unit agreement address the manner in which net profit interests will be computed after unitization and the effect of unitization of the operations under a lease upon a lessee's work commitment obligation. These recommendations have been rejected insofar as they relate to the development of provisions in the Model Unit Agreement published today. It would be premature at this time, to attempt to write unit agreement provisions addressing the impact of unitization upon Federal net profit interests or lessees' work commitment obligations. When the Department issues OCS oil and gas leases that incorporate net profit interests and/or lessee work commitment obligations, the Department will develop appropriate provisions for incorporation into the Model Unit Agreement then being used.

8. Unavoidable Delay.

A number of respondents recommended the addition of an "unavoidable delay" provision. This recommendation has not been adopted. The law and implementing regulations adequately cover unavoidable delay under suspension of production, i.e., under specified circumstances such as are identified in sections 5(a) and 25(h) of the Act. We expect to work with those unit operators who experience difficulties and delays in spite of vigorous efforts on their part. On the other hand, operators who encounter difficulties and delays which are due in a large part to their own lack of effort or their predecessor in interest's lack of effort will be expected to meet their obligations under the unit agreement in a timely manner.

MODEL UNIT AGREEMENT ARTICLE-BY-ARTICLE DISCUSSION

"Whereas Clauses"

One respondent recommended replacement of "in the national interest" in the second "whereas" clause with "in the interest of conservation, prevention of waste, and protection of correlative rights." This recommendation has not been adopted. Prior to the enactment of the 1978 OCS Lands Act Amendments, unitization was authorized only in those situations where unitization was "in the interest of conservation," i.e., conservation of the natural resources of the OCS. The statutory requirement that the Secretary prescribe regulations that include provisions "for unitization, pooling, and drilling agreements" contains no such constraining language. The broader provison to permit unitization "in the national interest" has been retained.

Article I—Definitions

One respondent recommended that "unitized area" be modified to permit the inclusion of adjoining State lands. This suggestion has not been adopted in recognition of the fact that the Model Unit Agreement is just what the title indicates it is, a model agreement for use in unitizing OCS oil and gas leases. In the event a unit is proposed which embraces State and Federal submerged lands, the language of the governing unit agreement should be drafted to clearly reflect that unique circumstance.

A number of respondents suggested that the Model Unit Agreement should include additional definitions of terms. Those suggestions were adopted to the extent that 30 CFR 250.2, "Definitions," were expanded to include definitions for "unitization," "unit area," "unit agreement," unitized substances," and "pooling and drilling agreements." The definition of a term contained in § 250.2 is controlling when that term is used in a unit agreement approved or prescribed under 30 CFR Part 250.

A number of editorial revisions have been made in the definitions contained in Article I. The most significant change made in the Article was the expansion of the definition of "lease" and the incorporation of language that recognizes the segregation of leases when less than an entire lease is included under a unit agreement.

Article III—Unit Area and Exhibits

Two respondents recommended the inclusion of an Exhibit C to show the allocation of production to the individual tracts of unitized lands. This recommendation has been adopted. A number of editorial changes have also been made to further clarify the provisions of Article III.

Article V—Resignation or Removal of Unit Operator

A number of respondents insisted that the

provisions of Articles IV, V, and VI that relate to the designation, resignation, and replacement of the unit operator should be omitted from the unit agreement and left in the unit operating agreement. This idea has been rejected. The unit operating agreement is a companion but subordinate agreement to the unit agreement. The provisions in question demonstrate the involvement of the Director or his delegee in the process relating to the designation, resignation, and replacement of a unit operator.

A number of respondents recommended that § 5.3 indicate that the assets to be turned over to the successor unit operator should be limited to those that are jointly owned by the working interest owners. This suggestion has not been adopted. The complex picture of ownership of OCS assets makes it imperative that the successor unit operator receive control over those assets that are necessary to continue unit operations. The agreements between the unit operator, the working interest owners, and the owners of assets used in unit operations should reflect the importance of continued operation of the unit after the resignation or removal of a unit operator and the selection of a successor unit operator.

Article VI--Successor Unit Operator

A number of respondents recommended that a basis other than acreage be used to measure the weight of a working interest owner's vote to remove or designate a unit operator. This suggestion has been adopted. Section 6.1 has been modified to indicate that a working interest owner's share will be "determined on the basis of the estimated volume of recoverable oil or gas, or both, originally in place under each lease computed on the basis of reservoir characteristics."

One respondent recommended that § 6.2 be modified to permit the Director to designate a successor unit operator, if the working interest owners have failed to designate a successor unit operator. This recommendation has been adopted. Section 6.2 now provides the Director the options of terminating the unit agreement or of designating one of the working interest owners as successor unit operator. As the respondent suggested, the conservation of natural resources of the OCS may not be served by the termination of a unit agreement. The Director's authority to require unitization clearly carries with it the authority to designate a unit operator.

Article VII--Unit Operating Agreement

Only minor editorial changes have been made in the text of this Article. The recommendations that: (1) The requirement to submit amendments to unit operating agreements at least 30 days prior to their proposed effective dates be eliminated; (2) the unit operating agreement be limited to only one agreement; and (3) the filing of a unit operating agreement be permitted up to 30 days following the approval of the unit agreement have all been rejected. No amendment to a unit operating agreement is to become effective until the Director has had a reasonable period of time to object and prevent the provision from becoming effective should such action be appropriate. Any agreement which impacts upon the operations within the unit area may properly be considered part of the unit operating agreement. Since a working interest is not effectively committed to a unit agreement until it is committed to the unit operating agreement, the requirement that the executed unit operating agreement be submitted with the executed unit agreement has been retained. This practice will also assure that the provisions of the unit operating agreement are available for review by the Director's staff prior to the approval of the unit agreement. Should the unit operating agreement be found to contain objectionable features, appropriate changes can be obtained prior to the approval of the unit agreement.

Article IX--Appearances and Notices

Other than for some minor editorial changes, Article IX remains unchanged from the proposed provision published in August 1979, the recommendations that the unit operator be required to pay its own expenses for appearances or that the unit pay for appearances by non-operators have been rejected. One of the basic responsibilities of the unit operator is to represent the interest of the unitized activities before the Department of the Interior and other entities legally empowered to issue decisions concerning Orders and Regulations of the Department. Thus, it is proper that the expenses incurred by such appearances be treated as unit operating expenses. Non-operating working interest owners do not have the responsibility to represent any interest other than their own. Thus, it is proper for the unit agreement to indicate that a nonoperating working interest owner may make an appearance in any proceeding at its own expense.

Article X--(Exploration/Development and Production) Plans

Only minor editorial changes have been made in the text of Article X to assure that it clearly reflects the requirements for prompt and efficient exploration and development found in the Secretary's policy for prompt and efficient exploration and development of OCS oil and gas leases and unit areas and the regulations in 30 CFR Part 250, e.g., the regula-

tions in §§ 250.34, 250.35, 250.50, and 250.51, suggestions by respondents that the text of the Model Unit Agreement be changed to: (1) delete § 10.2; (2) allow a unit operator more time to submit a new exploration plan, or development and production plan; (3) indicate that any cessation or suspension authorized or approved under an approved exploration plan or development and production plan require no additional request or approval for a suspension; or (4) specifically provide for the amendment of exploration plans and development and production plans, have all been rejected. As previously indicated, the provisions of Article X are designed to reflect the Department's requirements for prompt and efficient exploration and development of OCS oil and gas leases and unit areas. The text of Article X makes it clear that just as an approved exploration plan or development and production plan cannot serve to extend a lease unless certain other actions are taken, the approval of a plan for unitized activities must also be accompanied by actions similar to those required to continue a lease without unitization, i.e., continuous drilling activity under § 250.35 or a suspension of operations or production pursuant to § 250.12.

Article XI—Revision of Unit Area

Article XI was the subject of a number of responses which in essence suggested that the requirements of the provision, as written, appeared to be unworkable. The text of Article XI has been modified to better reflect the requirements of the provisions contained therein. The question of whether a unit boundary is to be drawn by dividing blocks into aliquot parts has been left open to permit the definition of a unit area on the basis of actual estimated productive limits or upon the basis of aliquot parts of a block as shown in a protraction survey. Where reservoir limits are in the process of being defined, we envision that unit areas will be drawn on the basis of half, quarter, or quarter-quarter blocks. Once a unitized reservoir has been defined, the boundary may then be drawn on the basis of productive limits.

Article XII--Allocation of Production

Other than for some minor editorial changes, the text of Article XII is basically unchanged from the proposed Article XII published in August 1979.

Article XIII--Rentals and Minimum Royalties

One respondent recommended deletion of Article XIII on the grounds that rental and minimum royalty are adequately covered in the lease and regulations. This recommendation has been rejected. Since a unit agreement serves to amend the provisions of a lease that is subject to the agreement, it is appropriate to indicate in the unit agreement what, if any, change unitization will have on the rental and minimum royalty requirements of a lease. It is anticipated that appropriate "net profit" and "work commitment" provisions will be developed when leases are issued that incorporate these provisions.

Article XIV--Effective Date and Termination

One respondent recommended that Article XIV be modified to provide that the unit and each lease therein shall remain in full force and effect as long as the unitized area is being operated pursuant to an approved exploration plan or an approved development and production plan. This recommendation has not been adopted. The agreement, as written, makes it clear that there may be circumstances under which leases may expire or the unit agreement terminate even though an approved development and production plan is in effect, e.g., a cessation of production from the unit area that lasts more than 90 days when a suspension of operations or production is not in effect. There are some editorial changes in the text of Article XIV such as the modification to provide for a special effective date.

Article XV--Effect of Contraction and Termination; Article XVI--Counterparts; Article XVII-Subsequent Joinder; and Article XVIII--Remedies

The text of Articles XV, XVI, XVII, and XVIII as published today varies only slightly from the text of the provisions published in August. Recommendations by respondents that: (1) The unit operating agreement should be the exclusive business of the lessees; (2) the Director should be required to notify all operators of a pending termination of a unit agreement due to the unit operator's default; and (3) the Director should provide an opportunity for a hearing on the record prior to termination of a unit or lease have all been rejected. As previously indicated, the unit operating Agreement is subordinate to the unit agreement. Since the Director may require modifications of the unit agreement, the subordinate unit operating agreement cannot be exempt from the Director's authority to require modification. The lessees of unitized leases are responsible for assuring compliance with the unit agreement, law, regulations, and leases. The fact that another is serving as unit operator does not serve to reduce their responsibility. If anything, the lessee's responsibility is increased since the lessee must deal through a third party to assure timely action. The results of failure to recognize possible adverse results such as a lease

expiration or unit termination, or both, are problems which the lessee must address early in order to take effective action to assure timely actions on the part of the operator.

JOAN M. DAVENPORT,
Assistant Secretary

JUNE 20, 1980

7. Model Unit Agreement Form, 45 FR 43256, June 26, 1980.

Model Outer Continental Shelf Unit Agreement; Unit Agreement for Outer Continental Shelf Exploration, Development, and Production Operations on the ______ Unit, ______ Area Offshore ______

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Witnesseth:

Whereas, section 5(a)(4) of the Act authorizes the Secretary of the Interior to provide for unitization, pooling, and drilling agreements;

Whereas, it is deemed to be in the national interest to unitize the oil and gas interests in the Unit Area; and

Whereas, it is deemed to be in the national interest to conduct exploration, development, and production operations in the Unit Area in a timely and safe manner;

Now, Therefore, in consideration of the premises and promises contained herein, it is agreed that:

Article I--Definitions

The following definitions of terms shall apply to this Agreement.

(a) Act means the Outer Continental Shelf Lands Act of 1953, as amended, 43 U.S.C. 1331 et seq.

(b) Regulations means all regulations prescribed pursuant to the Act or sections 302 and 303 of the Department of Energy Organization Act, 42 U.S.C. 7152 and 7153. They include all regulations prescribed to carry out the provisions of the Act and as may be prescribed or amended at any time in order to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf (OCS) and the protection of correlative rights therein.

(c) Director means the Director of the Geological Survey, U.S. Department of the Interior, or his designee.

(d) Unit Area means the portion of the OCS which is made subject to this Agreement and described in Article III.

(e) Reservoir means an oil or gas accumulation which is separated from and not in communication with any other oil or gas accumulation.

(f) Working Interest means an interest in the Unit Area held by virtue of a Lease, operating agreement, or other contractual arrangement under which, except as otherwise provided in this Agreement, confers the right or authority to explore for, develop, and produce oil and gas. The right delegated to the Unit Operator by this Agreement is not a working interest.

(g) Lease means, according to the context, an oil and gas Lease issued or maintained pursuant to the Act, or a specific area of the OCS for which the United States has conveyed the exclusive right and privilege to drill for, mine, extract, remove, and dispose of oil and gas deposits including a portion of such an area segregated in accordance with 30 CFR 250.50.

(h) Block means an area designated as a block on a United States Official Leasing Protraction Diagram for an area of the OCS.

(i) Unit Operator means the person, association, partnership, corporation, or other business entity designated by the Working Interest owners and approved by the Director to conduct operations within the Unit Area in accordance with exploration plans and development and production plans approved pursuant to the Act and applicable Regulations.

(j) Agreement means this unit agreement, approved by the Director for conducting exploration, development, and production operations within the Unit Area.

(k) Unit Operating Agreement means an agreement made between the Working Interest owners and the Unit Operator providing for the apportionment of costs and liabilities incurred in conducting operations pursuant to this Agreement and the establishment of such other rights and obligations as they deem appropriate.

Article II--Incorporation by Reference

This Agreement is subject to all provisions of the Act, sections 302 and 303 of the Department of Energy Organization Act, the Regulations, other applicable laws, and the Leases covering OCS lands within the Unit Area.

Article III--Unit Area and Exhibits

3.1 The following described portion of the OCS as shown on the United States Official Leasing Protraction Diagram is subject to valid Leases and constitutes the Unit Area.

3.2 Exhibit "A", which is attached to this Agreement and made a part hereof, is a plat identifying the Unit Area and component Blocks.

3.3 Exhibit "B", which is attached to this document and made a part hereof, is a schedule listing the component Leases and the ownership of each.

3.4 Exhibit "C", which is attached to this Agreement and made a part hereof, is a schedule listing the component Leases and the percentage of oil or gas, or both, that is to be allocated to each Lease or portion of a Lease.

3.5 Exhibits "A," "B," and "C" shall be revised by the Unit Operator whenever changes in the Unit Area, changes in the ownership of one or more Leases, or changes in the percentages of oil or gas, or both, allocated to the individual Leases render such changes necessary. Four copies of the revised exhibits shall be submitted for concurrence of the Director.

Article IV--Designation of Unit Operator

__________ is designated as the Unit Operator and agrees to accept the rights and obligations of the Unit Operator to explore for, develop, and produce oil and gas as provided in this Agreement.

Article V--Resignation or Removal of Unit Operator

5.1 The Unit Operator shall have the right to resign at any time. Such resignation shall not become effective until 60 days after written notice of an intention to resign has been delivered by the Unit Operator to the Working Interest owners and the Director and until all artificial islands, installations, and other devices, including wells, used for conducting operations in the Unit Area are placed in a condition satisfactory to the Director for suspension or abandonment of operations. However, if a successor Unit Operator is designated and approved as provided in Article VI, the resignation shall be effective upon the designation and approval of the successor Unit Operator.

5.2 The Unit Operator may be subject to removal by the same percentage vote of the owners of Working Interests as provided in Article VI for the designation of a successor Unit Operator. This removal shall not be effective until the Working Interest owners notify the Director and the Unit Operator and until the Director approves the designation of a successor Unit Operator.

5.3 The resignation or removal of the Unit Operator shall not release the Unit Operator from liability for any failure to meet his obligations which accrued before the effective date of his resignation or removal.

5.4 The resignation or removal of the Unit Operator shall not terminate his right, title, or interest as the owner of a Working Interest or other interest in the Unit Area. However, when the resignation or removal of the Unit Operator becomes effective, the Unit Operator shall relinquish to the successor Unit Operator all artificial islands, installations, devices, records, and any other assets used for conducting operations on the Unit Area, whether or not located on the Unit Area.

Article VI--Successor Unit Operator

6.1 Whenever the Unit Operator tenders his resignation as Unit Operator or is removed as provided in Article V, a successor Unit Operator may be designated by (a) affirmative vote of the owners of a majority of the Working Interests, based on their respective shares (determined on the basis of the estimated volume of recoverable oil or gas, or both, originally in place under each Lease computed on the basis of reservoir characteristics) in the Leases subject to this Agreement, and (b) the successor Unit Operator's acceptance in writing of the rights and obligations of a Unit Operator. The successor Unit Operator shall file with the Director four executed copies of the designation of successor. However, the designation shall not become effective until approved by the Director.

6.2 If no successor Unit Operator is designated as herein provided within 60 days following notice to the Director of the resignation or removal of a Unit Operator, the Director, at his election, may designate one of the Working Interest owners other than the Unit Operator as successor Unit Operator, or he may declare this Agreement terminated.

Article VII--Rights and Obligations of Unit Operator

Except as otherwise provided in this Agreement and subject to the terms and conditions of approved exploration and development and production plans, the exclusive rights and obligations of the owners of Working Interests to conduct operations to explore for, develop, and produce oil and gas in the Unit Area are delegated to and shall be exercised by the Unit Operator. This delegation neither relieves a lessee of the obligation to comply with all Lease terms nor transfers title to any Lease or operating agreement.

Article VIII--Unit Operating Agreement

8.1 The owners of Working Interests and the

Unit Operator shall enter into a Unit Operating Agreement which shall describe how all costs and liabilities incurred in maintaining or conducting operations pursuant to this Agreement shall be apportioned and assumed. The Unit Operating Agreement shall also describe how the benefits which may accrue from operations conducted on the Unit Area shall be apportioned.

8.2 The owners of Working Interests and the Unit Operator may establish by means of one or more Unit Operating Agreements such other rights and obligations as they deem necessary or appropriate. However, no Unit Operating Agreement shall be deemed to modify the terms and conditions of this Agreement or to relieve the Working Interest owners or the Unit Operator of any obligation set forth in this Agreement. In case of any inconsistency or conflict between this Agreement and a Unit Operating Agreement, the terms of this Agreement shall prevail.

8.3 Three copies of the Unit Operating Agreement executed in conjunction with the first paragraph of this Article shall be attached to this Agreement when it is filed with the Director with a request for approval. Three copies of all other Unit Operating Agreements and any amendments to Unit Operating Agreements also shall be filed with the Director at least 30 days prior to their proposed effective dates.

Article IX--Appearances and Notices

9.1 The Unit Operator shall have the right to appeal on behalf of all Working Interest owners before the Department of the Interior or any other body legally empowered to issue decisions concerning orders or Regulations of the Department and to appeal from these decisions. The expense of these appearances shall be paid and apportioned as provided in a Unit Operating Agreement. However, any affected Working Interest owner shall have the right at his own expense to be heard in any proceeding.

9.2 Any order or notice relating to this Agreement which is given to the Unit Operator by the Director shall be deemed given to all Working Interest owners of the Unit Area. All notices required by this Agreement to be given to the Unit Operator or the owners of Working Interests shall be deemed properly given if they are in writing and delivered personally or sent by prepaid registered or certified mail to the addresses set forth below or to such other addresses as may have been furnished in writing to the party sending the notice.

Article X--(Exploration/Development and Production) Plans

10.1 The Unit Operator shall submit (exploration/development and production) plans pursuant to the Act and the Regulations. All operations within the Unit Area shall be conducted in accordance with an approved plan.

10.2 When no oil or gas is being produced in paying quantities from the Unit Area and when all or part of the Area is subject to one or more Leases beyond the primary term, a continuous drilling or well reworking program shall be maintained with lapses of no more than 90 days per lapse between such operations unless a suspension of production or other operations has been ordered or approved by the Director. Plans may call for a cessation of drilling operations for a reasonable period of time between the initiation of actual production and the discovery and delineation of a reservoir when such a pause in drilling activities is warranted to permit the design, fabrication, and erection of platforms, artificial islands, installations, and other devices needed for development and production operations, provided a suspension of production or other operations has been ordered or approved by the Director.

10.3 An acceptable exploration plan or development and production plan and accompanying environmental report shall be submitted at the time this Agreement is filed for the Director's approval. Each (exploration/development and production) plan shall expire on the date specified in the plan, but not later than 30 days following completion of the last drilling or other operation described in the plan. At least 60 days before the scheduled expiration of any plan, unless for good cause the Director grants an extension, the Unit Operator shall file an acceptable subsequent (exploration/development and production) plan and accompanying environmental report for approval in accordance with this Article.

Article XI--Revision of Unit Area

11.1 Prior to the commencement of production of oil or gas from a Reservoir which is subject to this Agreement, the Unit Operator shall advise the Director as to whether he believes the Unit Area should be adjusted and shall describe the portion of the Unit Area that he regards as capable of production in paying quantities from the Reservoir. The Unit Operator shall, at the same time, submit a schedule setting forth the percentage of oil and gas to be allocated to each Lease or part of a Lease covering lands within the area identified as capable of production in paying quantities from the Reservoir. The identification of the area of productivity shall be effective when approved by the Director and shall, thereafter, comprise the Unit Area. The provisions of Article XV shall apply to those Leases or portions of Leases which are eliminated from this Agreement as a result of a revision under this provision.

11.2 Subject to the approval of the Director, the Unit Area may be further revised by additions necessary for Unit Operations or for the inclusion of an area capable of production in

paying quantities from the Reservoir for which the unit Area is established, or by reduction to exclude an area not capable of production in paying quantities from the Reservoir for which the Unit Area is established.

11.3 The Unit Area shall not be reduced on account of the depletion of oil and gas from the Reservoir for which it was established, but any Unit Area established under the provisions of this Article shall terminate automatically whenever operations are permanently abandoned in the Reservoir.

11.4 At any time, the Unit Area may be contracted by the Director to insure that the Unit Area includes only that area underlain by one or more oil and gas Reservoirs or one or more potential hydrocarbon accumulations to be served by an optimal number of platforms, artificial islands, installations, or other devices necessary for the efficient exploration for or development and production of oil and gas. The Director may condition approval of a development and production plan for the Unit Area on acceptance of this contraction requirement.

Article XII--<u>Allocation of Production</u>

12.1 The Unit Operator shall pay all production royalties and make deliveries of oil and gas which are payments of royalties taken in kind or which, pursuant to the Act, are purchased by the United States. For the purpose of allocating production for the determination of royalty or net profit shares accruing under this Agreement, each Lease or part of a Lease shall have allocated to it such percentage of the oil and gas saved, removed, or sold from the Unit Area [as the number of acres of the Lease or part of a Lease included in the Unit Area bears to the total number of acres in the Unit Area or as may be determined on the basis of the estimated volume of recoverable oil or gas, or both, originally in place under each Lease or portion of a Lease computed on the basis of Reservoir characteristics]. The oil and gas saved, removed, or sold from a Unit Area shall be allocated in this manner, regardless of where any well is drilled in the Unit Area.

12.2 The allocation of oil and gas saved, removed, or sold for purposes other than for settlement of the royalty obligations of the Working Interest owners or the settlement of a net profit share shall be on the basis prescribed in a Unit Operating Agreement, whether in conformity with the basis of allocation set forth above or otherwise.

12.3 For the purpose of determining royalty obligations, gas and liquid hydrocarbon substances on which royalty has been paid and which is used for repressuring, stimulation of production, or increasing ultimate recovery from the Unit Area, in conformity with an approved development and production plan, may be deemed to be a portion of the gas and liquid hydrocarbon substances subsequently saved, removed, or sold from the Unit Area. In such instances, a like amount of gas and liquid hydrocarbon substances similar to that previously used, less appropriate deduction for loss or depletion from any cause, may be saved, removed, or sold from the Unit Area without paying a royalty thereon. However, as to gas, only dry gas and not products extracted therefrom may be saved, removed, or sold royalty-free. The royalty-free withdrawal shall be accomplished in accordance with an approved development and production plan, and the shares of gas and liquid hydrocarbon substances withdrawn that are to be recognized as free of royalty charges shall be computed in accordance with a formula approved or prescribed by the Director. Any withdrawal of royalty-free gas or liquid hydrocarbon substances shall terminate upon the termination of this Agreement. For the purposes of this paragraph, liquid hydrocarbon substances include natural gasoline and liquid petroleum gas fractions.

Article XIII--<u>Rentals and Minimum Royalties</u>

13.1 Rentals are payable in advance on or before the anniversary date of each Lease included in the Unit Area. Rentals shall be paid by the lessees of record.

13.2 For each Lease year commencing on or after the effective date of this Agreement and after the Director has determined that a well on the Unit Area is capable of being produced in paying quantities, a minimum royalty of $3 an acre/year shall be paid for each acre or fraction thereof under Lease within the Unit Area. However, if there is production from the Unit Area during the Lease year, the amount of royalty paid for production allocated to the Lease during the Lease year shall be credited against the minimum royalty obligation. Minimum royalties are payable within 30 days after the last day of each Lease year and shall be paid by the Unit Operator.

Article XIV--<u>Effective Date and Termination</u>

14.1 This Agreement shall be effective on (Date) __________ and shall terminate when oil and gas is no longer being produced from the Unit Area and drilling or well-reworking operations are no longer being conducted in accordance with an exploration plan or development and production plan approved for the Unit Area.

If the Director has ordered a suspension of operations or production on all or part of the Unit Area pursuant to 30 CFR 250.12, this Agreement shall be continued in force and effect for the period of suspension, provided the suspension is applicable to two or more leases.

14.2 This Agreement may be terminated, with

the approval of the Director, at any time by an affirmative vote of the owners of a majority of the Working Interests either based on their respective shares of the acreage subject to this Agreement or as otherwise specified in the Unit Operating Agreement.

Article XV—Effect of Contraction and Termination

15.1 Any Lease or portion of a Lease, insofar as it covers any portion of the OCS excluded from the Unit Area pursuant to this Agreement, may be maintained only in accordance with the terms and conditions contained in the Act, the Regulations, and the Lease. Operations conducted in the Unit Area and suspensions approved or ordered for all or part of the Unit Area shall not serve to maintain an excluded Lease or an excluded portion of a Lease.

15.2 Upon termination of this Agreement, the Leases committed hereto may be continued in force and effect in accordance with the terms and conditions contained in the Act, the Regulations, and the Leases.

Article XVI—Counterparts

This Agreement may be executed in any number of counterparts, no one of which needs to be executed by all parties, and, after the effective date, shall be binding upon all parties who have previously executed a counterpart with the same force and effect as if all parties have signed the same document.

Article XVII—Subsequent Joinder

The Director may order or, upon request, approve a subsequent joinder to the Unit Agreement pursuant to the expansion provisions of Article XI. A request for a subsequent joinder shall be accompanied by a signed counterpart to this Agreement and shall be submitted by the Unit Operator at the time he submits a notice of proposed expansion pursuant to Article XI. A subsequent joinder shall be subject to the requirements which may be contained in the Unit Operating Agreement, if any, except that the Director may require modifications of any provision in a Unit Operating Agreement which he finds would prevent or frustrate a subsequent joinder.

Article XVIII—Remedies

18.1 The failure of the Unit Operator to conduct operations in accordance with an approved exploration plan or development and production plan, to timely submit an acceptable plan and accompanying environmental report for approval by the Director, or to comply with any other requirement of this Agreement in a timely manner shall, after notice of default or notice of prospective default to the Unit Operator by the Director and after failure of the Unit Operator to remedy any default within a reasonable time as determined by the Director, result in automatic termination of this Agreement effective as of the first day of the default.

18.2 This remedy is in addition to any remedy which is prescribed in the Act, the Regulations, or a Lease committed to this Agreement or any action which may be brought by the United States to compel compliance with the provisions thereof.

In Witness Whereof, the Working Interest owners and the Unit Operator have caused this Agreement to be executed, and the Director has approved this Agreement as follows:

Approval by Director

Pursuant to the authority vested in the Secretary of the Interior under the Act and delegated to the Director, U.S. Geological Survey, I approve this Agreement for exploration, development, and production on the ______ Unit, ______ Area, Outer Continental Shelf.

Effective Date of Agreement ______________

Dated: ______________________________

____

Director, U.S. Geological Survey

Acceptance of Rights and Obligations by Unit Operator

I hereby accept and assume all rights and obligations of the Unit Operator as set forth above.

Dated: ______________________________

Authorized Signature: ______________

Name: ______________________________

Title: ______________________________

Corporation: ________________________

Address: ___________________________

Subscribed and sworn to me this ______ day of ______ 19 ______.

Notary Public: ______________________

My Commission Expires: ______________

Approval by Working Interest Owner

As an owner of a Working Interest in the Unitized Area, I hereby agree to the terms and conditions as set forth in this Agreement.

Dated: ______________________________

Authorized Signature: ______________

Name: ______________________________

Title: ______________________________

Corporation: ________________________

Address: ___________________________

Subscribed and sworn to me this ______ day of ______ 19 ______.

Notary Public: ______________________

My Commission Expires: ______________

K. 30 CFR 251, Geological and Geophysical Explorations of the Outer Continental Shelf, Title 30 CFR, revised as of July 1, 1980.

1. Preamble, 30 CFR 251, Geological and Geophysical (G&G) Explorations, 45 FR 6338, January 25, 1980.

DEPARTMENT OF THE INTERIOR

Geological Survey

30 CFR Part 251

Geological and Geophysical (G&G) Explorations of the Outer Continental Shelf

AGENCY: Department of the Interior, U.S. Geological Survey.

ACTION: Final rule.

SUMMARY: This rule incorporates the modifications required to conform 30 CFR Part 251 with the Outer Continental Shelf (OCS) Lands Act, as amended, 43 U.S.C. 1331 et seq. (herein referred to as the "Act"). A proposed rule was published on February 9, 1979, in the Federal Register (44 FR 8302). The proposed rule described new procedures and, to the extent required by the Act, modifications to existing practices and procedures that govern prelease geological and geophysical explorations of the OCS.

EFFECTIVE DATE: This rule shall become effective March 25, 1980.

ADDRESSES: A copy of this rule may be obtained from the following offices of the Geological Survey:

Deputy Division Chief, Offshore Minerals Regulation, U.S. Geological Survey, National Center--Mail Stop 640, 12201 Sunrise Valley Drive, Reston, Virginia 22092

Conservation Manager, Eastern Region, U.S. Geological Survey, 1725 K Street N.W., Suite 204, Washington, D.C. 20006

Conservation Manager, Gulf of Mexico Region, U.S. Geological Survey, 131 Imperial Office Building, P.O. Box 7944, Metairie, Louisiana 70010

Conservation Manager, Pacific OCS Region, U.S. Geological Survey, 1340 West Sixth Street, Room 160, Los Angeles, California 90017

Assistant Conservation Manager, Alaska Area, U.S. Geological Survey, 800 "A" Street, Anchorage, Alaska 99501.

FOR FURTHER INFORMATION CONTACT:

Gordon D. Burton, Branch of Marine Evaluation, Conservation Division, U.S. Geological Survey, Mail Stop 640, 12201 Sunrise Valley Drive, Reston, Virginia 22092, (703) 860-7564.

SUPPLEMENTARY INFORMATION:

BACKGROUND

Rules establishing practices and procedures under which the U.S. Geological Survey (herein referred to as the "Survey") administers geological and geophysical exploration activities on the OCS were effective June 11, 1976, and were published as Part 251 of Title 30 of the Code of Federal Regulations on June 23, 1976 (41 FR 25891). The Survey published a proposed revision of 30 CFR Part 251 in the Federal Register on February 9, 1979, (44 FR 8302). The proposed revisions incorporated modifications required to bring the provisions of Part 251 into conformance with the Act and to implement a decision by the Secretary of the Interior to allow the drilling of prelease onstructure deep stratigraphic tests. The most important changes related to: (1) Giving permittees the option of drilling deep stratigraphic tests either onstructure or offstructure; (2) Requiring the submittal of an Environmental Report prior to drilling a deep stratigraphic test; (3) Allowing a penalty for late participation in a deep stratigraphic test after the Director issues a public notice of significant shows or a possible discovery of up to 200 percent of the cost to any of the original participants; (4) Requiring deep stratigraphic tests to be completed no later than 3 months prior to the month in which the relevant Proposed Notice of Sale appears on the Secretary's currently approved OCS Leasing Schedule; (5) Requiring all deep stratigraphic tests to be considered expendable and to be permanently plugged and abandoned; (6) Clarifying what will be released to the public by the Director in the event hydrocarbon accumulations are encountered in a deep stratigraphic test; and (7) Allowing the Director to disclose information or data to independent contractors, with a promise to maintain its confidentiality, for analysis or processing on the Government's behalf.

This final rule puts into effect most of these changes and incorporates additional changes which can be summarized as follows: (1) The requirement for the filing of notices for scientific research has been modified so that filing of a notice is required before any shallow test drilling for scientific research may commence; however, permits will continue

to be required for scientific research which involves the use of solid or liquid explosives or a deep stratigraphic test; (2) In order to comply with section 402(b) of the Act, a provision pertaining to the Fishermen's Contingency Fund has been added; (3) The maximum allowable penalty for late participation in a deep stratigraphic test after the Director has announced a hydrocarbon occurrence has been raised from 200 to 300 percent; (4) Language requiring permittees to notify the Director of all hydrocarbon occurrences detected in the drilling of a deep stratigraphic test and allowing the Director to make a public announcement of occurrences considered significant has been added; (5) Subsections 251.11(a) and (b) and 251.12(a) and (b) have been expanded to require the submission, upon request by the Director, of interpreted geological and geophysical information; (6) The proprietary term for data relating to a deep stratigraphic test that is not within 50 miles of an OCS oil and gas lease has been extended from 5 to 10 years; (7) Procedures dealing with the manner in which privileged or proprietary information or data will be provided to the designated representative of a Governor pursuant to section 8(g) of the Act have been added; and (8) The provisions pertaining to the disclosure of data and information relating to specific contractual commitments have been clarified.

COMMENTS

A total of 39 parties submitted timely comments in response to the invitation contained in the notice of the proposed rule published February 9, 1979. These comments represented the views of 2 private citizens, 3 environmental organizations, 8 State and local Governments, and 26 oil and gas companies and trade organizations.

PUBLIC HEARINGS

Oral testimony concerning the proposed revisions of 30 CFR Part 251 was also taken at a public hearing held in Washington, D.C., on May 8, 1979.

DISCUSSION OF FORMAT CHANGE

As part of the Survey's effort to comply with Executive Order 12044, all of its OCS regulations have been rewritten to make them as simple and clear as possible. As a result, the format and contents of 30 CFR Part 251 have been significantly restructured since they were published as a proposed rule on February 9, 1979. This final rule is organized in such a way as to clarify the procedures to be followed and the requirements to be met by those parties conducting prelease geological and geophysical activities on the OCS. In general, the format has been altered to reflect the sequence of activities which comprise the permitting process. Also, related procedures have been grouped together in a more easily understood manner.

DISCUSSION OF MAJOR COMMENTS

Deep Stratigraphic Test: Numerous comments were received on the Department's decision to expand the definition of "deep stratigraphic test" to include the option of allowing either the drilling of onstructure or offstructure deep stratigraphic tests. The major concerns expressed in comments were: The impact of this decision on the proposed lease sale schedule; The environmental and economic implications of the increased potential for the discovery of hydrocarbons during prelease onstructure test; The impact on competition within the oil and gas industry; The threat of increased Federal involvement in presale drilling operations; and The statutory authority of the Government to permit onstructure tests.

Many respondents opposed allowing onstructure drilling because they felt it would delay OCS leasing in the most promising frontier areas. They argued that the Department would be under increasing pressure to wait until frontier areas are thoroughly evaluated before offering them for sale. Other commenters expressed concern that this would increase pressures for the Government to begin drilling deep stratigraphic tests, which they regarded as the first step toward the creation of a Federal oil and gas company. We disagree with both of these viewpoints. First, there is nothing new or unusual about drilling deep stratigraphic tests in advance of offshore lease sales. The deep stratigraphic test program is already in place and is well known. Although deep stratigraphic tests, whether they are drilled on- or offstructure increase the amount of prelease information available to the Government, we recognize the limitations associated with the use of this information. The Department does not foresee delay or cancellation of sales on the basis of information gained from deep stratigraphic tests. In fact, the regulations specifically state that all deep stratigraphic tests must be completed 3 months prior to a Proposed Notice of Sale, if the test is within 50 geographic miles of tracts to be included in the sale. Second, the final rule simply allows the Secretary to authorize industry to drill stratigraphic test onstructure as well as offstructure. Industry, and not the Government, will initiate proposals for the drilling of onstructure tests.

Some respondents expressed concern over the environmental risks associated with the increased potential for the discovery of hydrocarbons during onstructure tests. In response to this concern, the final rule has been modi-

fied to state that the permittee must utilize the best available and safest technologies for drilling activities as prescribed or approved by the Director. Also, it should be noted that hydrocarbons have been encountered in two off-structure deep stratigraphic tests, the COST B-3 in the Mid-Atlantic and the Point Conception test off the coast of California, and adequate precautions were taken by industry to prevent any damage to the environment.

Some commenters insisted that the public announcement of hydrocarbon occurrences will have an adverse economic impact on a lease sale. They presume that a positive announcement would inflate lease bids, and no public announcement would reduce bids. We do not agree. The economic impact will occur primarily as a result of the information and data which participants derive from the test well rather than from the Director's announcement. The information that hydrocarbons are or are not present is only one of many factors considered by private industry and the Government in estimating the resource potential of an area. It is hoped that the announcement will encourage expanded group participation in sharing the cost of deep stratigraphic tests because participants will benefit by having early access to all information derived from the drilling activities. The additional information will also provide potential bidders (and the Federal Government) a better basis on which to access the value of individual offshore tracts prior to a lease sale. This should enable industry to better utilize its capital assets and provide Federal revenues that more fully reflect the resources that eventually may be discovered in the OCS lands.

Several commenters expressed the view that onstructure tests will, contrary to the Department's point of view, decrease industry competition and discourage participation by smaller, independent companies. We continue to believe that prelease onstructure test drilling will enhance competition for offshore tracts by providing smaller companies additional information to somewhat reduce risks associated with participation in offshore lease sales.

Several commenters contended that the Department does not have the authority to permit onstructure drilling activities before a lease is issued. They base their argument on the fact that the Act does not specifically authorize such activities. Departmental policy is based on existing legal authority which states:

"Any agency of the United States and any person authorized by the Secretary may conduct geological and geophysical explorations in the Outer Continental Shelf, which do not interfere with or endanger actual operations under any lease maintained or granted pursuant to this Act, and which are not unduly harmful to aquatic life in such area. (43 U.S.C. 1340)"

This matter was discussed during congressional debate over the proposed amendments to the OCS Lands Act of 1953. During the deliberations, the Department made it clear that it believed it could authorize onstructure drilling activities prior to the issuance of a lease. The House-Senate Conference Report makes it clear that the conferees accepted this argument:

"The conferees' action does not indicate any intention to limit, modify, or expand whatever authority the Government has under existing law to grant permits to applicants to conduct drilling operations (Conference Report on OCS Lands Act Amendments of 1978, Report No. 95-1091, page 101)."

The Secretary's decision to allow onstructure drilling was made in an effort to obtain additional information about the hydrocarbon potential of an OCS sale area, information which cannot be obtained by drilling only offstructure.

Several commenters endorsed the policy of prelease onstructure tests and agreed that these will provide more information with which to evaluate the resource potential of an area prior to leasing.

Some respondents recommended that onstructure tests be required in all areas prior to offering tracts at a lease sale. We have not adopted this suggestion. This approach was vigorously debated by Congress during its consideration of amendments to the OCS Lands Act of 1953 and was not adopted.

Drilling plan and environmental report: Numerous comments were received on the requirements for a Drilling Plan and Environmental Report contained in § 251.6-2 of the final rule. Several respondents argued that the stated requirements are too stringent. We do not share this point of view. Both the Drilling Plan and Environmental Report are necessary to enable the Survey and affected States to monitor activities associated with the drilling of deep stratigraphic tests and to identify and evaluate the environmental consequences that may result from the proposed drilling.

Furthermore, the information required in the Environmental Report coincides with the information that may be provided to States when required by approved coastal zone management programs for use by the State in evaluating the permittee's consistency certification.

Several respondents did not feel it necessary to include a description of the proposed drilling rig in the Drilling Plan if this information has previously been submitted to the Director. We have adopted this suggestion and have accordingly modified the final rule.

One commenter objected to the requirement that an oil spill contingency plan be part of the Drilling Plan because of the Short term duration

of test drilling. Because onstructure drilling increases the possibility that a deep stratigraphic test will detect hydrocarbons, and oil spill contingency plan is required in case there is an accidental spill. We chose, instead, to expand this requirement by accepting the recommendation that the oil spill contingency plan include a description of the onshore disposal procedures for spilled oil and oil-soaked debris. Improper disposal of spilled oil and oil-soaked debris can cause greater environmental problems than the original incident and must be considered in a comprehensive contingency plan.

One respondent requested that the Director establish special regulatory requirements to address varying regional conditions to ensure protection of the marine environment. We have rejected this suggestion. The evaluation of specific regional considerations falls within the scope of the Environmental Report and, we feel, is best administered through the proposed procedure which grants the Director the authority to issue special orders governing activities under specific regional conditions.

The same respondent recommended that the regulations require the use of the best available and safest technologies during prelease drilling activities. We have adopted the suggestion to insure maximum protection of the environment during drilling activities.

Several commenters requested that the nonproprietary portions of the Drilling Plan and Environmental Report be made available to interested Federal Agencies and to affected States or affected local jurisdictions. Subsection 251.6-2(c) states that the Director will make copies of the Environmental Report available to the public, in accordance with established Departmental practices and procedures. This section has been expanded to allow the Director to transmit copies of the Drilling Plan (except for those portions which the Director determines are exempt from disclosure) and the accompanying Environmental Report to the Governors of affected States.

We have adopted the suggestion to allow cross-referencing of recent applicable Environmental Impact Statements in the Environmental Report in order to avoid redundancy.

Several commenters questioned the need for the Director to require permittees to file Coastal Zone Management Act consistency certification with their Drilling Plan. The Coastal Zone Management Act provides that when OCS permit activities impact on the land use or water use of a State with an approved coastal zone management program, the applicant for a permit must obtain the State's concurrence in a consistency certification prior to permit approval of the Director.

Some respondents expressed concern that costly delays might result from the requirement that modifications to the Drilling Plan must receive the Director's rather than the Supervisor's approval. Specifying the Director as the approving authority is not intended to change the present practices and procedures under which the Area Oil and Gas Supervisors and District Supervisors administer the provisions of 30 CFR Part 251. The Survey intends through a Delegation of Authority, to delegate line authority for this program to the appropriate field supervisory level. We have adopted this approach so that the pending administrative reorganization within the Survey's Conservation Division can be accomplished without the need to subsequently modify the contents of this final regulation.

Disclosure of data and information submitted under permit: Many comments were received with regard to the provision in the proposed rule which required immediate public notice of "hydrocarbon shows" or "hydrocarbon discoveries" when the Director determines that shows or discoveries are "significant." After analyzing the comments we agree with those that believe this provision, as proposed, is too ambiguous. To counter this problem, we have reworded the text to discuss only "hydrocarbon occurrences" and have provided a definition of this term in section 251.2. We did not, however, adopt the recommendation that the public announcement be dropped altogether. We believe this type of notice will lead to increased participation in the deep stratigraphic test program and in increased competition at the time of a lease sale.

Comments were received requesting extension of the period for protection of proprietary data from deep stratigraphic tests that are not within 50 miles of an OCS oil or gas lease. This recommendation has been adopted. The time period for protecting proprietary information and data has been extended from 5 to 10 years after completion of the drilling activities. The new time period conforms with the time period established in subsection 251.14-1 for protecting other geological information and data. The disclosure provisions have been revised to state that, in addition to test data, all information and data obtained from, and submitted in support of, an application for a deep stratigraphic test will also be available to the public.

Several comments were received relating to 30 CFR Part 252 suggesting that the regulations implementing section 8(g) of the Act should be in Part 251. This suggestion has been adopted. Subsection 251.14-3 has been expanded to include provisions required to implement section 8(g) of the Act.

Several comments addressed the need for a provision in the regulations to control the release of information and data where such release is specifically prohibited under a contractural commitment. In response to these comments, subsection 251.14-4 has been added to

protect privileged and proprietary information and data from disclosure if the release is specifically prohibited under a contractual commitment.

SECTION-BY-SECTION DISCUSSION

Section 251.1 Purpose

No comments were received on § 251.1. However, the wording was changed to clarify that these regulations encompass geological and geophysical activities, not authorized by a lease, both for exploration for mineral resources and for scientific research which involves the use of solid or liquid explosives or drilling activities.

Section 251.2 Definitions

The definitions have been alphabetized and some have been rewritten so that they conform to the format and substance of the definitions contained in 30 CFR 250.2, 30 CFR 252.2 and 43 CFR 3300.0-5.

One respondent recommended the inclusion of a definition for "cultural resource." We have adopted this suggestion. The language used was derived from the cultural resource stipulations inserted in recent oil and gas leases.

We have modified the definition for "notice" because of our decision to require the filing of notices only for scientific research which involves shallow test drilling. Also, we revised the definition for "geological or geophysical scientific research" to include only those scientific research activities which involve the use of solid or liquid explosives or drilling activities.

We have adopted the suggestion of one commenter to modify the definition of "analyzed geological information" to include the results of formation fluid test (i.e., wire-line formation samplers and drill-stem tests).

We have added a definition for the term "hydrocarbon occurrences" which is used throughout the regulations in place of the terms "significant hydrocarbon shows" and "possible hydrocarbon discoveries." The regulations now require permittees to report all hydrocarbon occurrences detected during drilling operations. Subsection 251.14-1(c)(1) requires the Director to determine if the reported occurrences are significant and, if they are to make a public announcement. The announcement will be in a form and manner prescribed by the Director. We recognize that the Director's determination of the "significance" of hydrocarbon occurrences is subjective. However, flexibility is important because a hydrocarbon occurrence that may be judged significant in one area may not be considered significant in another area. The geographic location of the borehole, water depth, economic factors, the position of the test on a geologic structure, and other factors must enter into the determination of "significance."

Two comments were received on the definition of "geological exploration for mineral resources" requesting the deletion of the phrase "including, but not limited to." This recommendation has not been adopted. The phrase in question emphasizes that the activities listed are examples rather than an all inclusive listing of the activities.

Several commenters objected to the use of the term "sonic" in the definition of "analyzed geological information" because it is also a registered trademark name. We have, therefore, substituted the term "acoustic" for "sonic" in the definition and throughout the text of the regulations.

Numerous comments were received on the Department's decision to expand the definition of "deep stratigraphic test" to include the option of allowing onstructure drilling of tests as well as offstructure drilling of tests. This issue was discussed previously in the "Discussion of Major Comments" section.

Section 251.3 Administrative Authority and Applicability

Section 251.2, "Applicability" in the proposed rule, has been moved to § 251.3 and retitled. The regulations in this final rule are applicable to any permit issued after or unexpired as of the effective date of this rule. Notices filed after the effective date of this final rule shall also be subject to the regulations in this Part.

One commenter suggested that this section should specifically authorize the Director to prescribe stipulations on onstructure drilling permits. The commenter expressed the belief that stipulations are better suited to specific situations than an OCS Order. We have not adopted this suggestion. It should be noted, however, that the Director may incorporate any conditions (stipulations) into a permit that the Director determines to be necessary to protect the environment or to meet special local conditions.

We have decided to eliminate the requirement for filing of notices for scientific research activities on the OCS which do not involve shallow test drilling. The original provision was included so that the Survey could keep track of all scientific research activities on the OCS, but we now feel that this approach is impractical. However, we will continue to require permits for scientific research which involves the use of solid or liquid explosives or deep stratigraphic test drilling. Moreover, we have not adopted the suggestion that a provision be included under this subsection that permits archaeologists to examine the results obtained from geological or geophysical

exploration for mineral resources. We feel that subsection 251.6-2(e), which relates to cultural resources, adequately covers the review by the Department of cultural resources detected under permit activities.

One commenter suggested expanding the language of § 251.3-5(a)(6) to set specific requirements for identifying and reporting adverse effects on cultural resources. This recommendation was not adopted because these procedures are discussed under § 251.6-2(e). Also, one commenter suggested deleting the reference to cultural resources in this section. This recommendation was not adopted. It is the responsibility of the Department of the Interior to insure, to the extent practicable, that cultural resources are not disturbed by activities under the jurisdiction of the Department on the OCS.

Section 251.4 of the proposed rule, "Functions of Director," has been incorporated into § 251.3 of the final rule. One respondent recommended that the authority for issuing permits be retained by the Supervisor. As we indicated before, the modification in the text of these regulations is not intended to significantly change the present practices and procedures under which the field supervisors administer the provisions of Part 251.

Also, we have not adopted the suggestion of one commenter to add the words "the environment" after "or waste of" in this section. This sentence states that the Director may issue orders to prevent the waste of natural resources. We believe the language of the regulation is clear, as written, and it is not clear to us what "waste of the environment" means.

One commenter recommended the addition of cultural resources to the language of this section as one of the things protected under the Orders issued by the Director. We have not adopted this suggestion. The provisions necessary to prevent damage to cultural resources are adequately covered under § 251.6-2(e).

Several respondents suggested modifying § 251.3-5(b) by deleting the requirement for reporting "possible hydrocarbon discoveries." This recommendation, as we mentioned earlier, has been modified to require the reporting of all hydrocarbon occurrences to the Director.

Subsection 251.3-5(b) has been expanded to require the reporting of environmental hazards to the Director. This is intended to encompass hazards encountered during exploration activities which constitute an imminent threat to human activity on the OCS.

Section 251.4 Geological and Geophysical Activities Requiring Notices or Permits

Section 251.5 of the proposed rule, "Requirement of notices and permits," has been retitled "Geological and geophysical activities requiring notices or permits" and moved to § 251.4 of the final rule. This section has been rewritten to modify the requirement for the submission of notices for certain types of scientific research. The primary purpose of these regulations is to insure that geological and geophysical exploration for mineral resources on the OCS is conducted in a timely and environmentally sound fashion. We recognize, however, our responsibility to insure that particular activities conducted for scientific reasons are also conducted in an environmentally sound fashion. Accordingly, scientific research which involves the use of solid or liquid explosives or test drilling will be subject to the requirements of the provision of § 251.4.

Several commenters objected to the issuance of permits being at the "discretion" of the Director. We believe those commenting misunderstood the meaning of this language. Before approving a permit application, the Director must determine that it is in conformance with the applicable laws, regulations, and OCS Orders prior to issuance. We have, however, eliminated the language because the section makes it clear that activities must be approved by the Director before they can commence.

We have not adopted the suggestion to require cultural resource surveys before issuance of permits for scientific research. Departmental policy specifically states that it is an objective of the OCS program not to disturb cultural resources. We feel that § 251.6-2(e) adequately addresses the protection of cultural resources. This subsection provides that cultural resource studies will be conducted, if required by the Director, prior to the commencement of a deep stratigraphic text regardless of whether the test is drilled under a permit for the exploration for mineral resources or a permit for scientific research.

Finally, the last sentence of § 251.4-1 has been rewritten in response to the suggestion that any statement of rejection shall (as opposed to may) advise the applicant of changes necessary to make the application acceptable.

Section 251.5 Applying for Notices or Permits

Section 251.6, "Forms for notices and permit applications," in the proposed rule has been moved to § 251.5, and retitled "Applying for notices or permits" in the final rule. We have adopted the recommendation of several respondents that more flexibility be built into the requirement that permittees indicate the commencement and completion dates for exploration activities in the drilling plan. We have included wording to indicate that proposed dates of commencement and completion are to be submitted with the application for a permit. We have not adopted the suggestion that permittees be exempt from complying with any statutes,

regulations, or orders enacted, promulgated, issued, or amended after a permit is issued. This would be contrary to the requirements of section 5(a)(1) of the Act. For OCS exploratory activities to be conducted in the safest manner practicable, compliance with all applicable statutes, regulations, and orders is necessary, including those issued during the course of operations.

A new § 251.5-5, has been added to include a provision required by section 402 of the Act which relates to the Fishermen's Contingency Fund. As required by the Act, this provision will apply only to permits issued for geological and geophysical activities related to oil and gas exploration.

Section 251.6 Test Drilling Activities

Section 251.9 in the proposed rule, "Test drilling under notices and permits," has been moved to § 251.6 and retitled "Test drilling activities." The recommendation that the requirement that permittees gather and submit high-resolution geophysical data be deleted has been rejected. This information is necessary for the Director to insure the safety of drilling operations and the protection of the environment. Accordingly, this final rule allows the Director to require submission of geophysical information and data sufficient to determine shallow structural detail prior to approval of drilling activities.

Several new subsections were added to incorporate the Coastal Zone Management Act requirements. When a State with an approved coastal zone management program has included in its program or in writing an indication that a proposed activity subject to a Federal permit is likely to affect the land uses and water uses of the State's coastal zone, the Director will transmit copies of the permit application and the appropriate consistency certification to the State and shall make copies available to appropriate Federal Agencies and the public. The State must concur or be conclusively presumed to concur in the applicant's consistency certification, or the Secretary of Commerce must make the finding authorized by section 307(c)(3)(B)(iii) of the Coastal Zone Management Act, before the Director may issue the permit.

Several commenters requested deletion of § 251.6-2(e), which pertains to cultural resources, because the required surveys are an economic burden. These recommendations have not been adopted. It is the responsibility of the Department of the Interior to insure that there is a minimum disturbance to cultural resources by OCS activities approved by the Department.

One commenter suggested deleting the requirement in § 251.6-2(g) that deep stratigraphic tests be permanently plugged and abandoned after the completion of the test. We have not adopted this recommendation. To assure maximum protection of the marine environment, these boreholes will continue to be considered expendable. One commenter requested that § 251.6 be amended to provide for review and concurrence by the State agency before permits are issued for onstructure shallow or deep tests in areas within 3 miles of the seaward boundary of the State. We have not adopted this recommendation. However, the Survey will forward a copy of the applicant's Drilling Plan and Environmental Report to the State, for review, prior to approving drilling operations. If the State has an approved coastal zone management program, the applicant may also have to receive the State's concurrence in a consistency certification prior to the commencement of operations.

Several comments were received concerning the regulations dealing with group participation. Most of these commenters felt the penalties for late participation in a deep stratigraphic test should be increased. We agree in part with these suggestions. We have decided not to change the maximum penalty (i.e., 100 percent of the cost to each original participant in addition to the original share cost) for late entry into a deep stratigraphic test. We feel that this amount is sufficient to encourage the early participation of most interested parties, but is not overly burdensome to others, such as smaller companies, which may take longer to acquire sufficient funds in order to enter the group. We have, however, raised the maximum penalty for late participants who wait until after the Director announces a hydrocarbon occurrence to enter the group to 300 percent of the cost to each original participant in addition to the original share cost. We feel that this provision will protect those involved in the initial drilling consortium from companies that want to buy into the consortium only after hydrocarbon occurrences are detected in a test and will encourage early participation in such a consortium.

The comment was also made that the penalties should be assessed by the participants and shared by all parties who participated as of the time the hydrocarbon occurrence is announced. We believe that the amount and distribution of monetary penalties should be spelled out in the initial agreement between the participants as a further stimulus for early participation. For clarity, we have adopted the suggestion to reword subsection 251.6-3(d) to read "if the applicant proposes changes" to indicate that the applicant and not the Director proposes the changes.

One commenter suggested adding the following language to the last sentence of the above cited section: "...unless a significant show has been encountered in which case they shall be considered late participants." This commenter felt this change would protect the rights

of the original participants. We have reworded this subsection to make it clear that if an applicant changes the original permit application and the Director determines that the change is significant, the applicant must readvertise the activity in order to allow others to participate. Participants entering under this readvertisement must be considered original participants.

We have modified § 251.6-4 to require a corporate surety bond of $50,000 instead of $100,000. This was done in order to parallel the bonding requirements that the Bureau of Land Management imposes on lessees under 43 CFR 3318.

Several respondents requested that provision be made in § 251.6-5 for flexibility in the requirement that drilling of deep stratigraphic tests be completed at least 3 months prior to the first day of the month in which the Proposed Notice of Sale is listed on the currently approved OCS Leasing Schedule. In order to allow for unexpected delays after the commencement of drilling operations, we have added the following: "However, the Director may extend the expiration date of a permit if it is determined that such an extension is in the national interest."

Section 251.7 Inspection and Reporting of Progress and Results of Activities Conducted Under Permits

Section 251.10, "Observation of exploration conducted under permits" has been retitled and moved to § 251.7-1 in the final rule. Two commenters asked for clarification of the terms "advisor" and "Federal representative." For clarity, we have combined the two terms into "Federal representative." The Federal representative, who is appointed or approved by the Director or a subordinate authorized to act on the Director's behalf, will observe or inspect operations conducted pursuant to a permit. The contents of § 251.8, "Report of operations conducted under notices and permits," have been moved to § 251.7. As we pointed out earlier, permittees will not be required to report "possible hydrocarbon discoveries." However, any "hydrocarbon occurrences" must be reported to the Director who will then determine their significance.

Section 251.8 Suspension and Cancellation of Authority to Conduct Activities Under Permit

Section 251.15, "Termination, suspension, and revocation of authority to operate under notices and permits" has been modified and incorporated into § 251.8.

This section has been rewritten to define cancellation as a permanent revocation of a permit. Cancellation notices will be issued 30 days prior to becoming effective. A suspension is of a temporary nature and shall require all operations conducted under a permit to cease immediately. In order to permit immediate implementation of an order, language has been added to allow the Director to suspend permits either orally or in writing. Oral suspensions will be followed by written confirmation.

Several comments were received objecting to the right of the Director to terminate permits without cause. In the revision of this section, the Director is required to state the reason for the cancellation of a permit.

Section 251.9 Penalties

Section 251.16, "Penalties," has been moved to § 251.9. No comments were received on this section and only minor editorial changes were made.

Section 251.10 Appeals

Section 251.17, "Appeals," has been moved to § 251.10. No comments were received on this section and only minor editorial changes were made.

Section 251.11 Inspection, Selection, and Submission of Geological Information and Data

Section 251.12, "Inspection, selection, and submission of data and information," has been subdivided into § 251.11 "Inspection, selection, and submission of geological information and data" and § 251.12, "Inspection, selection, and submission of geophysical information and data." In implementing the requirements of section 26 of the Act, and in conformance with the procedures contained in 30 CFR Part 252, §§ 251.11 and 251.12 have been expanded to include the inspection, selection and submission of interpretations as part of the information and data requirements.

We do not agree with comments that state that § 251.11(b)(7), which allows the Director to specify other geological data and analyzed or interpreted geological information, is too broad and "open-ended." Section 26(a)(1)(A) of the Act requires a permittee conducting exploration pursuant to the Act to "... provide the Secretary access to all data and information (including processed, analyzed, and interpreted information) obtained from such activity and shall provide copies of such data and information as the Secretary may request." We believe the latitude afforded to the Secretary by the Act is properly reflected in the language of the regulations.

Section 251.12 Inspection, Selection, and Submission of Geophysical Information and Data

Several commenters questioned whether permittees will be required to submit original information and data to the Director for inspection, rather than copies. Section 26(a)(1)(A) of the Act requires lessees or permittees to provide copies of information and data as the Secretary may request. We have not adopted the suggestion of one commenter that permittees be reimbursed for shipping costs incurred in submitting information and data to the Director for inspection. Section 26 of the Act requires the Secretary to reimburse the permittee for reproducing and processing information and data Shipping costs do not fall into that category.

Several commenters recommended deleting § 251.12(b) which allows the Director to contract with parties outside the agency in order to reproduce data. We have not adopted this recommendation. The situation may arise where it would be more convenient or more economical for the Director to arrange for an independent contractor to reproduce the information or data. Several comments were received requesting that any third party reproducing information or data agree to protect the confidentiality of these materials. Subsection 251.14-2 has been rewritten to require an independent contractor, retained by the Director to reproduce information or data to sign a written commitment not to use the information or data in a manner other than is called for in the contract, and not to disclose the information or data to any third party without the written consent of the Director.

We have added "digital navigational data" as one of the items to be included with geophysical survey data in § 251.12(d)(1). These data are required by the Survey for use in constructing digital maps of geophysical surveys.

Several commenters recommended that language be added to § 251.12(d)(3) to indicate that the method of processing must be of a nature commonly available form geophysical contractors. We have not adopted this suggestion. We feel the Director needs access to the same processed and reprocessed information as is available to permittees.

Section 251.13 Reimbursement to Permittees

One commenter asked how the Department would establish a reimbursement rate for processing and reprocessing costs if no late participants had purchased data establishing such a rate. We feel that § 251.13(b), as stated, indicates that it is up to the permittee to justify the rate which the Director or any late participant will pay for processing or reprocessing of the data.

One comment was received objecting to the specific reference to fraudulent and collusive activity. Although fraudulent and collusive activity will continue to be prohibited, we have dropped the specific reference and have adopted language which reflects similar provisions in 30 CFR 252.3.

251.14 Disclosure of Information and Data Submitted Under Permits

The comments received regarding this section have been previously considered under "Discussion of Major Comments."

Authors: Thomas McCloskey, Office of the Assistant Secretary-Energy and Minerals, U.S. Department of the Interior (202/343-4457), Gordon D. Burton, Daniel S. Palubniak, and Leaman D. Harris, Geological Survey, U.S. Department of the Interior (703/860-7564).

ENVIRONMENTAL IMPACT AND REGULATORY ANALYSIS:

The Department of the Interior has determined that the revision of the regulations in 30 CFR Part 251, in accordance with this notice, is not a major Federal action significantly affecting the quality of the human environment and will not require preparation of an Environmental Impact Statement. The Department has also determined that this document is not a significant rule and does not require preparation of a regulatory analysis under Executive Order 12044 and 43 CFR Part 14.

CHARLES L. EDDY,
Acting Assistant Secretary of the Interior

JANUARY 22, 1980

2. Regulations, 30 CFR 251, Geological and Geophysical Exploration, Title 30 CFR, revised as of July 1, 1980.

PART 251--GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF.

AUTHORITY: Outer Continental Shelf Lands Act, 43 U.S.C. 1331 et seq.; as amended, 92 Stat. 629; National Environmental Policy Act of 1969, 42 U.S.C. 4321 et seq. (1970); Coastal Zone Management Act of 1972, as amended, 16 U.S.C. 1451 et seq.

SOURCE: 45 FR 6344, Jan. 25, 1980, unless otherwise noted.

§ 251.1 Purpose.

The Act authorizes the Secretary to prescribe rules and regulations necessary to carry out the provisions of the Act. The primary purpose of the regulations in this Part is to prescribe policies, procedures, and requirements for conducting geological and geophysical activities not authorized under a lease on the Outer Continental Shelf (OCS). These activities may take place on unleased lands or on lands under lease to a third party. These activities are limited to geological and geophysical exploration for mineral resources and geological or geophysical scientific research which involves the use of solid or liquid explosives or drilling activities. The requirements of the regulations in this Part implement the provisions of section 5, 8(g), 11(a) and (g), 19, 24, and 26 of the Act. Federal Agencies are exempt from the regulations in this Part.

§ 251.2 Definitions.

When used in this Part, the following terms shall have the meaning given below:

(a) "Act" means the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 et seq.).

(b) "Affected local government" means the principal governing body of a locality which is in an affected State and is identified by the Governor of that State as a locality which will be significantly affected by oil and gas activities on the OCS.

(c) "Affected State" means, with respect to any program, plan, lease sale, or other activity proposed, conducted, or approved pursuant to the provisions of the Act, any State:

(1) The laws of which are declared, pursuant to section 4(a)(2)(A) of the Act, to be the law of the United States for the portion of the OCS on which such activity is, or is proposed to be, conducted;

(2) Which is, or is proposed to be, directly

connected by transportation facilities to any artificial island or installation or other device permanently or temporarily attached to the seabed;

(3) Which is receiving, or in accordance with the proposed activity, will receive oil for processing, refining, or transshipment which was extracted from the OCS and transported directly to the State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Secretary as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment or a State in which there will be significant changes in the social, governmental, or economic infrastructure resulting from the exploration, development, and production of oil and gas anywhere in the OCS; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oil spill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

(d) "Analyzed geological information" means data collected under a permit or a lease which have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analyses, laboratory analyses of physical and chemical properties, well logs or charts, results and data obtained from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

(e) "Coastal environment" means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone.

(f) "Coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal States. The coastal zone includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches. The coastal zone extends seaward to the outer limit of the United States territorial sea and extends inland from the shoreline to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States, pursuant to the authority of section 305(b)(1) of the Coastal Zone Management Act.

(g) "Coastal Zone Management Act" means the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1451 et seq.).

(h) "Cultural resource" means a site, structure, or object of historical or archaeological significance.

(i) "Data" means facts and statistics or samples which have not been analyzed or processed.

(j) "Deep stratigraphic test" means drilling which involves the penetration into the sea bottom of more than 50 feet (15.2 meters) of consolidated rock or a total of more than 300 feet (91.4 meters).

(k) "Director" means the Director of the Geological Survey, U.S. Department of the Interior or a subordinate authorized to act on the Director's behalf.

(l) "Exploration" means the process of searching for minerals. Exploration activities include but are not limited to: (1) Geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of minerals, and (2) Any drilling, whether on or off a geological structure.

(m) "Gas" means any fluid, either combustible or noncombustible, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely; a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

(n) "Geological exploration for mineral resources" means any operation conducted on the OCS which utilizes geological and geochemical techniques, including, but not limited to, core and test drilling, well logging techniques, and various bottom sampling methods to produce information and data on mineral resources, including information and data in support of possible exploration and development activity. The term does not include scientific research.

(o) "Geophysical exploration for mineral resources" means any operation conducted on the OCS which utilizes geophysical techniques, including, but not limited to gravity, magnetic, and various seismic methods, to produce information and data in support of possible exploration and development activity. The term does not include scientific research.

(p) "Geological or geophysical scientific research" means any investigation conducted on the OCS using solid or liquid explosives, or drilling activities for scientific research purposes involving the gathering and analysis of geological or geophysical information and data which are made available to the public for inspection and reproduction at the earliest practicable time.

(q) "Governor" means the Governor of a State, or the person or entity designated by, or pursuant to, State law to exercise the powers granted to a Governor pursuant to the Act.

(r) "Human environment" means the physical, social, and economic components, conditions, and factors which interactively determine the state condition, and quality of living condi-

tions, employment, and health of those affected, directly, by activities occurring on the OCS.

(s) "Hydrocarbon occurrences" means the direct or indirect detection during drilling operations of any liquid or gaseous hydrocarbons by examination of well cuttings, cores, gas detector readings, formation fluid tests, wireline logs, or by any other means. The term does not include background gas, minor accumulations of gas, or heavy oil residues on cuttings and cores.

(t) "Information." when used without a qualifying adjective, includes analyzed geological information, processed geophysical information, interpreted geological information, and interpreted geophysical information.

(u) "Interpreted geological information" means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of data and analyzed geological information.

(v) "Interpreted geophysical information" means knowledge, often in the form of seismic cross sections and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

(w) "Lease" means (1) any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, minerals, or (2) the area covered by such authorization, whichever is required by the context.

(x) "Lessee" means the party authorized by a lease, or an approved assignment thereof, to explore for, develop, and produce the leased deposits in accordance with the regulations in Part 250 of this Chapter. The term includes all parties holding such authority by or through the lessee.

(y) "Marine environment" means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the OCS.

(z) "Minerals" includes oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals which are authorized by an Act of Congress to be produced from "public lands" as defined in Section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702).

(aa) "National Environmental Policy Act" means the National Environmental Policy Act of 1969 (42 U.S.C. 4321 _et seq._).

(bb) "Notice" means the statement of intent to conduct geological scientific research which involves shallow test drilling activities.

(cc) "OCS Order" means a formal numbered Order, issued by the Director, that implements the regulations contained in this Part and specifically applies to operations in an area in the Order.

(dd) "Oil" means any fluid hydrocarbon substance other than gas which is extracted in a fluid state from a reservoir and which exists in a fluid state under the existing temperature and pressure conditions of the reservoir. Oil includes liquefiable hydrocarbon substances such as drip gasoline or other natural condensates recovered or recoverable in a liquid state from produced gas.

(ee) "Operator" means the individual, partnership, firm, or corporation having control or management of operations on the leased area or a portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an approved operating agreement.

(ff) "Outer Continental Shelf' means all submerged lands which lie seaward and outside the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301), and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(gg) "Permit" means the contract or agreement, other than a lease, approved for a specified period of not more than 1 year under which a person acquires the right to conduct:

(1) geological exploration for mineral resources,

(2) geophysical exploration for mineral resources,

(3) geological scientific research,

(4) geophysical scientific research.

(hh) "Permittee" means the person authorized by a permit issued pursuant to this Part to conduct activities on the OCS.

(ii) "Person" means a citizen or national of the United States, an alien lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101(a)(20), a private, public, or municipal corporation organized under the laws of the United States or of any State or territory thereof, and associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States. The term does not include Federal Agencies.

(jj) "Pollution contingency plan" means the National Multi-Agency Oil and Hazardous Materials Pollution Contingency Plan or any successor plan thereto.

(kk) "Processed geophysical information" means data collected under a permit or a lease which have been processed. Processing involves changing the form of data so as to facilitate interpretation. Processing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

(ll) "Secretary" means the Secretary of the Interior or a subordinate authorized to act on the Secretary's behalf.

(mm) "Shallow test drilling" means drilling into the sea bottom to depths less than those specified in the definition of a deep stratigraphic test.

(nn) "Third party" means any person other than a representative of the United States or the permittee.

(oo) "Violation" means a failure to comply with any provision of the Act, or a provision of a regulation or order issued under the Act, or any provision of a lease, license, or permit issued pursuant to the Act.

§ 251.3 Administrative authority and applicability.

§ 251.3-1 Administrative authority.

Exploration or scientific research activities authorized or conducted under this Part shall be performed in accordance with the Act, the regulations in this Part, OCS Orders, other orders of the Director, and other applicable statutes and regulations, and amendments thereto.

§ 251.3-2 Functions of Director.

The Director shall regulate all operations and other activities under this Part and perform all duties prescribed by this Part. The Director is authorized to issue OCS Orders and other written and oral orders and to take all other actions necessary to carry out the provisions of this Part and to prevent harm or damage to, or waste of, any natural resource (including any mineral deposit in areas leased or not leased), any life (including fish and other aquatic life), property, or the marine, coastal, or human environment. The Director shall confirm oral orders in writing as soon as possible.

§ 251.3-3 Geological and geophysical activities under a lease.

The regulations in this Part shall not apply to geological and geophysical exploration conducted by or on behalf of the lessee on a lease on the OCS. Those exploration activities shall be governed by the regulations in Part 250 of this title.

§ 251.3-4 Geological and geophysical activities not under a lease.

The regulations in this Part are applicable to permits for geological and geophysical activities issued after or unexpired as of the effective date of this final rule. Notices filed after the effective date of this final rule shall also be subject to the regulations in this Part.

If the regulations in this Part conflict with the provisions of a permit which was issued under regulations published in the Federal Register on June 23, 1976 (41 FR 25893), the requirements of the permit shall govern, except for any requirements limiting the Director's authority to inspect and require the submission of interpretations derived from information and data acquired under those permits issued after January 27, 1978, as established by Part 252 of this title.

§ 251.3-5 General requirements of notices and permits.

(a) Geological and geophysical activities for mineral exploration or scientific research activities authorized under this Part shall be conducted so that those activities do not:

(1) Interfere with or endanger operations under any lease issued or maintained pursuant to the Act;

(2) Cause harm or damage to aquatic life;

(3) Cause pollution;

(4) Create hazardous or unsafe conditions;

(5) Unreasonably interfere with or harm other uses of the area; or

(6) Disturb cultural resources.

(b) Any person conducting geological or geophysical activities for mineral exploration or scientific research under this Part shall immediately report to the Director when these activities:

(1) Detect hydrocarbon occurrences;

(2) Encounter environmental hazards which constitute an imminent threat to human activity; or

(3) Adversely affect the environment, aquatic life, cultural resources, or other uses of the area in which the exploration activity is conducted.

(c) Any person conducting shallow test drilling or deep stratigraphic test drilling geological activities under a permit for mineral exploration or scientific research under this Part shall utilize the best available and safest technologies which the Director determines to be economically feasible.

(d) Authorization granted under this Part to conduct geological and geophysical exploration for minerals or for scientific research shall not confer a right to any discovered oil, gas, or other minerals, or to a lease under the Act.

§ 251.4 Geological and geophysical activities requiring notices or permits.

§ 251.4-1 Geological and geophysical exploration for mineral resources.

Geological or geophysical exploration for

mineral resources may not be conducted on the OCS without an approved permit unless such activities are being conducted pursuant to a lease issued or maintained under the Act. Separate permits must be obtained for geological exploration for mineral resources and for geophysical exploration for mineral resources. If the Director disapproves an application, the statement of rejection shall state the reasons for the denial, and shall advise the applicant of those changes needed to obtain approval.

§ 251.4-2 Geological or geophysical scientific research.

Geological or geophysical scientific research may not be conducted by any person on the OCS without an approved permit or filing of a notice unless such activities are being conducted pursuant to a lease issued or maintained under the Act.

(a) Separate permits must be obtained for geological scientific research and for geophysical scientific research which involves the use of solid or liquid explosives or the drilling of a deep stratigraphic test. If the Director disapproves an application, the statement of rejection shall state the reasons for the denial, and shall advise the applicant of the changes needed to obtain approval.

(b) A notice must be filed with the Director at least 30 days prior to the commencement of scientific research activities which involve shallow test drilling. Within 21 days of the filing of the notice, the Director may disapprove the notice by sending a statement of disapproval by certified mail to the person who filed the notice. If the Director disapproves the notice, the statement shall state the reasons for disapproval and shall advise the applicant of recommended changes.

§ 251.5 Applying for notices or permits.

§ 251.5-1 Permit forms.

(a) An application for a permit shall be submitted in a form and manner prescribed and approved by the Director. Each application for a permit shall include:

(1) The name of the person who will conduct the proposed exploration or research activity;

(2) The name of any person who will participate in the proposed exploration or research activity;

(3) The type of exploration or research activity and the manner in which the activity will be conducted;

(4) The location on the OCS where the exploration or research activity will be conducted;

(5) The prupose for conducting the exploration or research activity;

(6) The dates on which the exploration or research activity is proposed to be commenced and completed; and,

(7) Such other relevant information and data as the Director may require.

(b) This reporting requirement has been approved by the Office of Management and Budget in accordance with the Federal Reports Act of 1942 (042-5777002).

§ 251.5-2 Notices.

A notice shall not be on a standardized form, but shall be signed and shall state:

(1) The name of the person conducting or participating in the proposed research;

(2) The type of research and manner in which it will be conducted;

(3) The location, designated on a map, plat, or chart, where the research will be conducted;

(4) The dates, which shall designate a period of not more than 1 year, on which the research activity is proposed to be commenced and completed;

(5) The proposed time and manner in which the information and data resulting from the research will be made available to the public for inspection and reproduction, such time being the earliest practicable time;

(6) An agreement that the information and data resulting from the research will not be sold or withheld for exclusive use; and

(7) The name, registry number, registered owner, and port or registry of vessels used in the operation.

§ 251.5-3 Filing locations for permits to conduct exploration for mineral resources.

Each application for a permit to conduct geological or geophysical exploration for mineral resources in the OCS shall be filed, in duplicate, at the following locations;

(a) for OCS off the Atlantic Coast--the area Oil and Gas Supervisor for Resource Evaluation, Atlantic Area, U.S. Geological Survey, 1725 K Street N.W., Suite 204, Washington, D.C. 20006.

(b) For the OCS in the Gulf of Mexico--the Area Oil and Gas Supervisor for Resource Evaluation, U.S. Geological Survey, Gulf of Mexico Area, P.O. Box 7944, Metairie, Louisiana 70010.

(c) For the OCS off the coast of the States of California, Oregon, or Washington--the Area Oil and Gas Supervisor, U.S. Geological Survey, Pacific Area, Room 160, 1340 West Sixth Street, Los Angeles, California 90017.

(d) For the OCS off the State of Alaska--the Area Oil and Gas Supervisor, U.S. Geological Survey, Alaska Area, P.O. Box 259, Anchorage, Alaska 99510.

§ 251.5-4 Filing locations for notices or permits to conduct scientific research.

Each notice or application for a permit to

conduct geological or geophysical scientific research on the OCS shall be filed, in duplicate, at the locations indicated in subsection 251.5-3 of this section.

§ 251.5-5 Fishermen's Contingency Fund.

Upon the establishment of an account under the Fishermen's Contingency Fund for an area of the OCS pursuant to subsection 402(b) of the Act, the holder of a permit for geological or geophysical exploration activities for mineral resources in the area covered by the account shall pay an amount specified by the Secretary of Commerce for the purpose of the establishment and maintenance of an account for the area. At the time of issuing a permit, the Director shall collect the amount specified and deposit it in the Fund to the credit of the appropriate account.

§ 251.6 Test drilling activities.

§ 251.6-1 Permit or notice requirements for shallow test drilling.

The Director, prior to the commencement of shallow test drilling for exploration for mineral resources or for scientific research, may require for permits or recommend for notices the gathering and submission of geophysical information and data sufficient to determine shallow structural detail across and in the vicinity of the proposed test. Other information and data may include, but is not limited to, seismic, bathymetric, side-scan sonar, and magnetometer systems, across and in the vicinity of the proposed test. When required, §§ 251.6-2(c)(1) and (e) and 251.6-3 will apply to permits issued and notices filed for shallow test drilling.

§ 251.6-2 Permit requirements for a deep stratigraphic test.

(a) No deep stratrigaphic test drilling activities shall be initiated or conducted until a Drilling Plan has been submitted by the applicant and approved by the Director. The Drilling Plan shall include;

(1) The proposed type and sequence of drilling activities to be undertaken together with a timetable for their performance from commencement to completion;

(2) A description of the drilling rig proposed for use, unless a description has been previously submitted to the Director, indicating the important features thereof, with special attention to safety features and pollution prevention and control features, including oil spill containment and cleanup plans and onshore disposal procedures;

(3) The location of each deep stratigraphic test to be conducted, including the surface and projected bottomhole location of the borehole;

(4) The types of geophysical instrumentation to be used;

(5) Geophysical information and data sufficient to determine shallow structural detail across and in the vicinity of the proposed test, and other information and data from, but not limited to, seismic, bathymetric, side-scan sonar, and magnetometer systems, collected across any proposed drilling location, and other geophysical data from the area of the proposed test location, and processed geophysical information and interpreted geophysical information therefrom, so as to allow evaluation of structural detail to the total depth of the proposed test; and

(6) Such other relevant information and data as the Director may require.

(b) At the same time the applicant submits a Drilling Plan to the Director, an Environmental Report shall be submitted. The report shall be in summary form and should include information available at the time the related Drilling Plan is submitted. Such information is to be accurate, current, and applicable to the geographic area and the proposed activities covered by the plan. The applicant shall refer to information and data contained in the related plan, other Environmental Reports, and other environmental analyses and impact statements prepared for the geographic area by identifying the information and indicating a source for obtaining copies of the cited materials. Information and data which are site-specific, or which are developed subsequent to the most recent Environmental Impact Statement or other environmental analyses in the immediate area, shall be specifically considered. Specific guidelines for implementing this section will be issued by the Director. The Environmental Report shall include the following:

(1)(a) A list and description of new or unusual technologies that are to be used; (b) The location of travel routes for supplies and personnel; (c) The kinds and approximate quantities of energy to be used; (d) The environmental monitoring systems that are to be used; and (e) Suitable maps and diagrams showing details of the proposed project layout.

(2) A narrative description of the existing environment. This section shall include the following information on the area: (a) Geology; (b) Physical oceanography; (c) Other uses of the area; (d) Flora and fauna; (e) Existing environmental monitoring systems; and (f) Other unusual or unique characteristics which may affect or be affected by the drilling activities.

(3) A narrative description of the probable impacts of the proposed action on the environment and the measures proposed for mitigating these impacts.

(4) A narrative description of any unavoidable or irreversible adverse effects on the environment that could be expected to occur

as a result of the proposed action.

(5) Such other relevant information and data as the Director may require.

(c)(1) When required under a coastal zone management program approved under the Coastal Zone Management Act, the activities proposed by an applicant for a permit to conduct geological or geophysical exploration for minerals or for geological or geophysical scientific research must receive State concurrence in its coastal zone consistency certification prior to the Director's approval of any of the activities covered under the permit.

(2) The applicant shall submit a sufficient number of copies of the Drilling Plan and Environmental Report to permit the Director to transmit copies of each to the Governor of each affected State and the coastal zone management agency of each affected State that has a coastal zone management program approved under the Coastal Zone Management Act. The Director shall also make the Drilling Plan and accompanying Environmental Report available to appropriate Federal Agencies and the public, in accordance with established Departmental practices and procedures.

(d) Any revisions to an approved Drilling Plan must be approved by the Director.

(e) A permittee authorized to drill a deep stratigraphic test shall, if requested by the Director, conduct studies to determine whether any cultural resources exist in the area that may be affected by such drilling, and shall report the findings of those studies to the Director. A permittee authorized to perform shallow test drilling may be required to conduct similar studies if required by the Director. The study shall include a full description of any cultural resources detected. The permittee shall take no action that will result in the disturbance of cultural resources without the prior approval of the Director and, if any cultural resource is discovered after submission of the study (i.e., during site preparation or drilling), the permittee shall immediately report the discovery to the Director and make every reasonable effort to protect the cultural resource from damage until the Director has given directions as to its preservation.

(f) All OCS regulations relating to drilling operations in Part 250 of this title and all OCS Orders relating to the drilling of wells apply, as appropriate, to drilling activities authorized under this Part.

(g) At the completion of the test activities, the borehole of all deep stratigraphic tests shall be permanently plugged and abandoned by the permittee prior to moving the rig off location in accordance with the requirements of the regulations in Part 250 of this Chapter and applicable orders. If the tract on which deep stratigraphic test drilling has been conducted is later leased for exploration and development, the lessee will not be held responsible for the test hole, provided the lessee has not reentered or otherwise disturbed the borehole.

§ 251.6-3 Group participation in test drilling activities.

(a) In order to minimize duplicative geological exploration activities involving the penetration of the seabed of the OCS, a person proposing to drill a deep stratigraphic test shall afford all interested persons, through a signed agreement, an opportunity to participate in the drilling on a cost-sharing basis. The provisions of the agreement for sharing the cost of a deep stratigraphic test may include a penalty for late participants of not more than 100 percent of the cost to each original participant in addition to the original share cost. The participants shall assess and distribute penalties in accordance with the terms of the agreement. If the Director releases a public notice announcing a significant hydrocarbon occurrence, the penalty for subsequent late participants may be raised to not more than 300 percent of the cost of each original participant in addition to the original share cost.

(b) An applicant proposing to conduct shallow test drilling activities shall, when ordered by the Director or when provided in the permit, afford all interested persons an opportunity to participate in the test activity on a cost-sharing basis with a penalty for late participation of not more than 50 percent of the cost to each original participant.

(c) To allow for group participation in shallow or deep test drilling activities, the applicant shall:

(1) Publish a summary statement describing the proposed activity in a manner approved or prescribed by the Director;

(2) Forward a copy of the published statement to the Director;

(3) Allow at least 30 days from the date of publishing the summary statement for other persons to join as original participants;

(4) Compute the estimated cost to an original participant by dividing the estimated total cost of the program by the number of original participants; and

(5) Furnish the Director with a complete list of all participants under the permit prior to commencing operations, or at the end of the advertising period if operations begin prior to its close. Also, the names of all late participants shall be forwarded to the Director.

(d) If the applicant proposes changes to the original application and the Director determines that such changes are significant, the Director shall require a republication of the changes and an additional 30 days for other persons to join as original participants.

§ 251.6-4 Bonds.

Before a permit authorizing the drilling of a deep stratigraphic test will be issued, the applicant shall furnish to the Bureau of Land Management a corporate surety bond of not less than $50,000 conditioned on compliance with the terms of the permit, unless the applicant maintains with or furnishes to the Bureau of Land Management a bond in the sum of $300,000 conditioned on compliance with the terms of the permit issued to him for the area of the OCS where the applicant proposes to conduct the drilling of a deep stratigraphic test. The Director may require the submission of a bond before authorizing the initiation of shallow test drilling. Any bond furnished or maintained by a person under this section shall be on a form approved or prescribed by the Director, Bureau of Land Management.

§ 251.6-5 Duration of exploration activities.

If a deep stratigraphic test well is drilled within 50 geographic miles of any tract tentatively selected for a lease sale as listed on the currently approved OCS Leasing Schedule, all drilling activities must be completed, and the information and data submitted to the Director, at least 3 months prior to the first day of the month in which the Proposed Notice of Sale is listed. However, the Director may extend the expiration date of a permit if it is determined that such an extension is in the national interest.

§ 251.7 Inspection and reporting of progress and results of activities conducted under permits.

§ 251.7-1 Inspection and observation of exploration activities.

(a) A permittee, upon request by the Director, shall furnish food, quarters, and transportation for Federal representatives. Upon request, the permittee will be reimbursed by the United States for the actual costs incurred as a result of providing food, quarters, and transportation for a Federal representative's stay of more than 10 hours. The Federal representative shall observe or inspect operations conducted pursuant to the permit and determine whether operations are having any adverse effects upon the environment, aquatic life, cultural resources, or other uses of the area.

(b) The Federal representatives shall be appointed or approved by the Director.

§ 251.7-2 Progress report on activities conducted under a permit.

Each permittee shall submit status reports on a weekly basis in a manner approved or prescribed by the Director. This shall include a daily log of operations.

§ 251.7-3 Final report on activities conducted under a permit.

Each permittee shall submit to the Director a final report of exploration or scientific research activities under the permit within 30 days after the completion of operations. The final report shall contain the following:

(a) A description of the work performed.

(b) Charts, maps, or plats depicting the areas and blocks in which any exploration or scientific research activities were conducted, specifically identifying the lines of geophysical traverses or the locations where geological exploration or scientific research activities were conducted, including a reference sufficient to identify the data produced during each activity.

(c) The dates on which the actual exploration or scientific research activities were performed.

(d) A narrative summary of any: (1) Hydrocarbon occurrences or environmental hazards, and
(2) Adverse effects of the exploration or scientific research activities on the environment, aquatic life, cultural resources, or other uses of the area in which the activities were conducted.

(e) Such other descriptions of the activities conducted as may be specified by the Director.

§ 251.8 Suspension and cancellation of authority to conduct activities under permit.

(a) The Director may suspend or temporarily prohibit the permittee's authority to conduct exploration or scientific research activities under a permit by notifying the permittee either orally or in writing when the Director determines that there is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment. Such suspensions shall be effective immediately upon receipt of the notice. Suspensions issued orally shall be followed by a written notice confirming the action, and all written notices will be sent by certified mail. A suspension shall remain in effect until the basis for the suspension has been corrected to the satisfaction of the Director.

(b) The Director may suspend or temporarily prohibit the permittee's authority to conduct exploration or scientific research under a permit either orally or in writing when the Director determines the permittee fails to comply with a provision of the Act or of any applicable law, the provisions of the permit, provisions of these and other applicable regulations, OCS Orders, or any other written orders or field rules including orders for the filing of reports and well records or logs within the time specified. Such suspensions shall be effective immediately upon receipt of the notice. Suspensions issued orally shall be followed by a written notice confirming the action and all written notices shall be sent by certified mail. A suspension shall remain in effect until the basis for the suspension has been corrected to the satisfaction of the Director.

(c)(1) The Director may cancel, or a permittee may relinquish, a permit to conduct exploration or scientific research activities at any time by sending a notice of cancellation or a notice of relinquishment. Such notices shall state the reason for the cancellation or relinquishment and shall be sent by certified mail to the other party at least 30 days in advance of the date the cancellation or relinquishment will be effective.

(2) Cancellation of a permit to conduct exploration or scientific research activities shall not relieve the permittee of the obligation to abandon any drill sites in accordance with the requirements of paragraph 251.6-2(g) of this Part and to comply with all other obligations specified in this Part or in the permit.

§ 251.9 Penalties.

All persons conducting geological or geophysical exploration activities for mineral resources or scientific research shall be subject to the penalty provisions of section 24 of the Act (43 U.S.C. 1350), the procedures contained in § 250.80 of this Chapter for noncompliance with any provision of the Act, or any provision of the permit, or for any violation of the provisions of any regulation or order issued under the Act. The penalties prescribed in this section shall be in addition to any other penalty afforded by any other law or regulation.

§ 251.10 Appeals.

Orders or decisions issued under the regulations in this Part may be appealed as provided in Part 290 of this Chapter.

§ 251.11 Inspection, selection, and submission of geological information and data.

(a) Each holder of a permit for geological exploration activities for mineral resources or scientific research shall notify the Director immediately in writing, of the acquisition, analysis, or interpretation of any geological information and data collected under the permit. All geological data, analyzed geological information, and interpreted geological information collected by the permittee shall be available for inspection by the Director. At any time within 1 year after receiving a notice of the acquisition, analysis, or interpretation of any geological information and data, the Director may select all or part of the geological data analyzed geolgical information and interpreted geological information. However, a longer period of time may be specified in the permit. The permittee shall submit reproducible copies of the information and data selected to the Director within 30 days following receipt of the Director's request, unless the Director authorizes a longer time period for the submission of the information or data.

(b) Each submission of geological data, analyzed geological information, and interpreted geological information shall contain, unless otherwise specified by the Director, the following:

(1) An accurate and complete record of all geological (including geochemical) data, analyzed geological information, and interpreted geological information resulting from each operation;

(2) Paleontological reports identifying microscopic fossils by depth, unless washed samples are maintained by the permittee for paleontological determination and are made available upon request for inspection by the Geological Survey;

(3) Copies of well logs or charts;

(4) Results and data obtained from formation fluid tests;

(5) Analyses of core or bottom samples or a representative cut or split of the core or bottom sample;

(6) Detailed descriptions of any hydrocarbons or hazardous conditions encountered during operations, including near losses of well-control, abnormal geopressure, and loses of circulation; and

(7) Such other geological data, analyzed geological information, and interpreted geological information as may be specified by the Director.

(c) In the event that geological data, analyzed geological information, or interpreted geological information is transferred from the permittee to a third party, or from a third party to another third party, the transferor shall notify the Director and shall require the receiving party, in writing, to abide by the obligations of the permittee as specified in this section as a condition precedent to the transfer of information or data.

§ 251.12 Inspection, selection, and submission of geophysical information and data.

(a) Each holder of a permit for geophysical exploration activities for minerals or scientific research shall notify the Director immediately, in writing, of the acquisition, processing, reprocessing, or interpretation of any geophysical information or data collected under the permit. All geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information collected by the permittee shall be available for inspection by the Director. At any time within 1 year after receiving a notice of the acquisition, processing, reprocessing, or interpretation of any geophysical information and data, the Director may select all or part of the geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information. However, a longer period of time may be specified in the permit.

(b) The Director shall have the right to inspect geophysical data, processed geophysical information, reprocessed geophysical information, or interpreted geophysical information prior to final selection. This inspection shall be performed on the permittee's premises unless the Director requests that the permittee deliver the information or data to the Director for inspection. Such delivery shall be within 30 days following the receipt of the Director's request unless the Director authorizes a later delivery date. At any time prior to final selection, the Director may return any or all geophysical information or data following either its inspection and detailed assessment of its quality, or the establishment of a price to the Government for the processing or reprocessing of the geophysical information or data. If the Director decides to keep all or a portion of the geophysical information and data, the Director shall notify the permittee, in writing, of this decision. If the inspection is done on the permittee's premises, the permittee shall submit the geophysical information or data selected within 30 days following receipt of the Director's request, unless the Director authorizes a longer period of time for delivery. The Director shall have the right to arrange, by contract or otherwise, for the reproduction, without the consent of the permittee, of geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information.

(c) In the event that geophysical data, processed geophysical information, reprocessed geophysical information, or interpreted geophysical information is transferred from the permittee to a third party, or from a third party to another third party, the transferor shall notify the Director and shall require the receiving third party, in writing, to abide by the obligations of the permittee as specified in this section as a condition precedent to the transfer of information or data.

(d) Each submission of geophysical data, processed geophysical information, reprocessed geophysical information and interpreted geophysical information, shall contain, unless otherwise specified by the Director, the following:

(1) An accurate and complete record of each geophysical survey conducted under the permit, including digital navigational data and final location maps of all survey stations;

(2) All seismic data developed under a permit presented in a format and of a quality suitable for processing;

(3) Processed geophysical information derived from seismic data with extraneous signals and interference removed, presented in a format and of a quality suitable for interpretive evaluation, reflecting state-of-the-art processing techniques; and

(4) Other geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information obtained from, but not limited to, shallow and deep subbottom profiles, bathymetry, side-scan sonar, gravity and magnetic surveys, and special studies such as refraction and velocity surveys.

§ 251.13 Reimbursement to permittees.

(a) After the delivery of geophysical data, processed geophysical information, and reprocessed geophysical information selected by the Director in accordance with § 251.12(b) of this Part, and upon receipt of a request for reimbursement and a determination by the Director that the requested reimbursement is proper, the permittee or third party shall be reimbursed for the cost of reproducing the selected information and data at the permittee's or third party's lowest rate or at the lowest commercial rate established in the area, whichever is less.

(b) After delivery of processed and reprocessed geophysical information selected by the Director in accordance with § 251.12(b) of this Part, and upon receipt of a request for reimbursement and determination by the Director that the requested reimbursement is proper, the permittee or third party shall be reimbursed only for the reasonable costs attributable to processing and reprocessing, as distinguished from the cost of data acquisition, as follows: (1) If the processing or reprocessing has been done by the permittee in the form and manner which is used by the permittee in the normal conduct of business, the Director shall pay the reasonable costs at the lowest rate at which the processed or reprocessed information is made available by the permittee to any party; or (2) If the process-

ing or reprocessing has been done in a form and manner as the Director may request other than that used in the normal conduct of the permittee's business, the Director shall pay the costs of processing and reprocessing such data.

(c) Requests for reimbursement are to contain a breakdown of costs in sufficient detail to allow separation of processing and reprocessing costs from acquisition costs.

§ 251.14 Disclosure of information and data submitted under permits.

§ 251.14-1 Disclosure of information and data to the public.

(a) The Director shall make information and data available in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2), the requirements of the Act, and the regulations contained in 30 CFR Part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), this Part, and 30 CFR Part 252 (Outer Continental Shelf Oil and Gas Information Program).

(b) Except as specified in this section or in Parts 250 and 252 of this Chapter, no information or data determined by the Director to be exempt from public disclosure under (a) of this section shall be provided to any affected State or be made available to the executive of any affected local government or to the public unless the permittee and all persons to whom such permittee has sold the information or data under promise of confidentiality agree to such an action.

(c) The Director shall disclose geological data, analyzed geological information, and interpreted geological information submitted under a permit as follows:

(1) The Director shall immediately issue a public announcement when any significant hydrocarbon occurrences are detected or environmental hazards are encountered on unleased lands during drilling operations. In the case of significant hydrocarbon occurrences, the Director will announce such occurrences in a form and manner that will futher the national interest without unduly damaging the competitive position of those conducting the drilling. Other information and data pertaining to the permit will be released according to the schedule provided in paragraphs (c)(2) or (3) of this section.

(2) The Director shall make available to the public all geological data, analyzed geological information, and interpreted geological information, except geological data, analyzed geological information, and interpreted geological information obtained from the drilling of a deep stratigraphic test, 10 years after the date of issuance of the permit under which the information and data was obtained.

(3) The Director shall make available to the public all geological data and information obtained from drilling a deep stratigraphic test 10 years after the completion date of the test or 60 calendar days after the issuance of the first OCS oil and gas lease within 50 geographic miles (92.6 kilometers) of the site of the completed test, whichever is sooner. The Director shall make available to the public all geological information and data submitted in support of an application for a permit to drill a deep stratigraphic test well at the earlier of the following times: (a) 10 years after completion of the test; or (b) 60 calendar days after the issuance of the first OCS oil and gas lease within 50 geographic miles (92.6 kilometers) of the site of the completed test.

(d) The Director shall disclose geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information submitted under a permit, and retained by the Director as follows:

(1) The Director shall make available to the public geophysical data 10 years after the date of issuance of the permit under which the data is obtained.

(2) The Director shall make available to the public processed geophysical information, reprocessed geophysical information, and interpreted geophysical information 10 years after the date it is submitted to the Director.

(3) The Director shall make available to the public processed geophysical information, reprocessed geophysical information, and interpreted geophysical information submitted in support of an application for a permit to drill a deep stratigraphic test, or which the permittee is required to obtain in order to conduct the drilling of a deep stratigraphic test, at the earliest of the following time; (a) 10 years after completion of the test; or (b) 60 calendar days after the issuance of the first OCS oil and gas lease within 50 geographic miles (92.6 kilometers) of the site of the completed test.

§ 251.14-2 Disclosure to independent contractors.

The Director reserves the right to disclose any information or data acquired from a permittee to an independent contractor or agent for the purpose of reproducing, processing, reprocessing, or interpreting such information or data. When practicable, the Director shall notify the permittee who provided the information or data of intent to disclose the information or data to an independent contractor or agent. The Director's notice of intent will afford the permittee a period of not less than 5 working days within which to comment on the intended action. When the Director so notifies

a permittee of the intent to disclose information or data to an independent contractor or agent, all other owners of such information or data shall be deemed to have been notified of the Director's intent. Prior to any such disclosure, the contractor or agent shall be required to execute a written commitment not to transfer or to otherwise disclose any information or data to anyone without the express consent of the Director. The contractor or agent shall be liable for any unauthorized use by or disclosure of information or data to third parties.

§ 251.14-3 Sharing of information with affected States.

(a) At the time of soliciting nominations for the leasing of lands within 3 geographic miles of the seaward boundary of any coastal State the Director, pursuant to the provisions of § 252.7(a)(4) and 252.7(b) of this Chapter and sections 8(g) and 26(e) of the Act, shall provide the Governor of the State the following information that has been acquired by the Director on such lands proposed to be offered for leasing:

(1) All information on the geographical, geological and ecological characteristics of the areas and regions proposed to be offered for leasing;

(2) An estimate of the oil and gas reserves in the areas proposed for leasing; and

(3) An identification of any field, geological structure, or trap located within 3 miles of the seaward boundary of the State.

(b) After the time of receipt of nominations for any area of the OCS within 3 geographic miles of the seaward boundary of any coastal State and tentative tract selection in accordance with the provisions of 43 CFR Parts 3313 and 3314, the Director, in consultation with the Governor of the State, shall determine whether any tracts being given further consideration for leasing may contain one or more oil or gas reservoirs underlying both the OCS and lands subject to the jurisdiction of the State.

(c) At any time prior to a sale, information acquired by the Director that pertains to the identification of oil or gas pools or fields underlying both the Outer Continental Shelf and lands subject to the jurisdiciton of any coastal State on tracts selected for leasing within 3 geographic miles of the seaward boundary of any such State will be shared, upon request and pursuant to the provisions of § 252.7(a)(4) and 252.7(b) of this Chapter and sections 8(g) and 26 of the Act, with the Governor of such State.

(d) Knowledge obtained by a State official who receives information under subsections (a) and (b) of this section shall be subject to the requirements and limitations of the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2), the Act, the regulations contained in 30 CFR Part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), the regulations in this Part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf), and the regulations contained in 30 CFR Part 252 (Outer Continental Shelf Oil and Gas Information Program).

§ 251.14-4 Disclosure of information and data relating to specific contractural commitments.

All information and data already received by the Director and covered by a specific contractual commitment concerning its release shall be handled in a way consistent with the contractural commitment. In the event of any conflict between this provision and a provision of any other regulation in this Part 251, or of any regulation in Part 250, this provision shall govern.

L. 30 CFR 252, Oil and Gas Information Program, Title 30 CFR 252, revised as of July 1, 1980.

1. Preamble, 30 CFR 252, Oil and Gas Information Program, 44 FR 46404, August 7, 1979.

DEPARTMENT OF THE INTERIOR

Geological Survey

30 CFR Part 252

Outer Continental Shelf (OCS) Oil and Gas Information Program

AGENCY: U. S. Geological Survey. Department of the Interior.

ACTION: Final rule.

SUMMARY: Issuance of this rule incorporates the modifications of 30 CFR Part 252 required by enactment of the Outer Continnntal Shelf (OCS) Lands Act Amendments of 1978 (92 Stat. 629). A proposed rule was published January 17, 1979 (44 FR 3524). The proposed rule described new procedures and, to the extent required, modifications of existing practices and procedures under which the Director of the Geological Survey makes certain information available to the Governors of affected States. Issuance of this final rule puts these practices and procedures into effect in compliance with the requirements and limitations of the provisions of the Freedom of Information Act (5 U.S.C. 552), the OCS Lands Act Amendments of 1978 (43 U.S.C. 1352), and other applicable law.

EFFECTIVE DATE: October 9, 1979.

ADDRESSES: A copy of this final rule may be obtained from the following offices of the Geological Survey:

Director, Geological Survey, National Center--Mail Stop 620, 12201 Sunrise Valley Drive, Reston, Virginia 22092.

Conservation Manager--Eastern Region, 1725 K Street, N.W., Suite 204, Washington, D.C. 20006.

Conservation Manager--Gulf of Mexico Region, 336 Imperial Office Building, P. O. Box 7944, Metairie, Louisiana 70010.

Conservation Manager--Western Region, 345 Middlefield Road, Menlo Park, California 94025.

Area Oil and Gas Supervisor--Pacific Area. 1340 West Sixth Street, Room 160, Los Angeles, California 90017.

Area Oil and Gas Supervisor--Alaska Area, 800 "A" Street, Suite 109, Anchorage, Alaska 99501.

FOR FURTHER INFORMATION CONTACT:
Gerald D. Rhodes, Branch of Marine Oil and Gas Operations, Conservation Division, U. S. Geological Survey, Mail Stop 620, 12201 Sunrise Valley Drive, Reston, Virginia 22092, (703) 860-7531.

SUPPLEMENTARY INFORMATION:

BACKGROUND

Regulations establishing practices and procedures under which the Director, Geological Survey, would make available Summary Reports of data and information to the Governors of affected States were published as final rules on January 27, 1978 (43 FR 3887). Those practices and procedures were set out in a new Part 252 of Title 30 of the Code of Federal Regulations entitled "Outer Continental Shelf (OCS) Oil and Gas Information Program." On September 18, 1978, the OCS Lands Act Amendments of 1978 were enacted (Pub. L. 95-372). Certain provisions of those Amendments (43 U.S.C. 1352) superseded the practices and procedures established by the current regulations in 30 CFR Part 252 and necessitated their revision. Proposed modifications of 30 CFR Part 252 were published as proposed rules on January 17, 1979 (44 FR 3524). The notice of proposed rulemaking identified the most significant revisions being proposed as the expansion of the scope of the information covered by the provisions of §252.5, "Information made available to affected States," and the addition of a new §252.7 entitled "Privileged and proprietary data and information to be made available to affected States."

COMMENTS

A total of 37 comments and recommendations were timely submitted in response to the invitation contained in the notice of proposed rule published January 17, 1979. The comments and recommendations varied widely as to their nature, scope, and content. Some were general in nature, while others were detailed and specific as to the recommended actions for the Department to initiate.

Respondents did not limit their comments to the proposed modifications of 30 CFR Part 252. Many of the comments reflected views expressed when the current provisions of the regulations governing the Outer Continental Shelf Oil and Gas Information Program were initially published as proposed rules on September 26, 1977 (42 FR 48893). The 37 responses that were

timely submitted presented the views of 2 private citizens, 3 special interest groups, 7 State and local government agencies, and 25 oil and gas companies and trade organizations.

PUBLIC HEARINGS

Oral testimony relating to the proposed revisions of 30 CFR Part 252 was also taken in addition to the written comments and recommendations invited by the notice of proposed rule. This oral testimony was taken at public hearings held in Los Angeles, California; New Orleans, Louisiana; and Washington, D.C.

DIFFERENCES BETWEEN PROPOSED RULE AND FINAL RULE

For the most part, the differences between the provisions of the final rule published today and the proposed rule published January 17, 1979, are the results of Departmental efforts to make the provisions of the final rule more closely conform with the provisions and intent of the OCS Lands Act, as amended, with special attention to the specific provisions and intent of section 26 of the Act (43 U.S.C. 1352). This closer conformance was accomplished through the incorporation of many of the comments and recommendations received from the public.

DISCUSSION OF MAJOR COMMENTS

GENERAL COMMENT

Need for Regulatory Analysis. Several respondents indicated a belief that implementation of the regulations, as proposed, represents a significant regulatory action that, pursuant to Executive Order 12044, requires preparation of a regulatory analysis. Prior to the publication of the modifications of 30 CFR Part 252, the Geological Survey prepared a Negative Declaration and Regulatory Analysis. That document examined the criteria for determining that a revision of regulations is a significant regulatory action requiring preparation of a regulatory analysis under Executive Order 12044. That review resulted in a determination that the proposed revision of 30 CFR Part 252 to implement the Outer Continental Shelf Lands Act Amendments of 1978 (Pub. L. 95-372) did not constitute a regulatory action requiring the preparation of a regulatory analysis under Executive Order 12044.

A review of that determination and the comments submitted by respondents failed to identify a basis or criteria which demonstrated any error in the previous negative determination or to justify any change in that determination. We, therefore, reaffirm our earlier finding that a regulatory analysis is not called for by the criteria set out in Executive Order 12044.

Section-by-Section Discussion

Section 252.1 Purpose

No specific comment or recommendation was received concerning the provisions of §252.1. However, comments and recommendations concerning specific provisions of other sections of Part 252 suggested the need to expand the language to § 252.1 to recognize the specific requirements of section 26 of the OCS Lands Act, as amended (43 U.S.C. 1352), as the primary motivation for the revision of the provisions of Part 252. Accordingly, the first sentence of 252.1 has been divided into two sentences which read:

"The purpose of this part is to implement the provisions of section 26 of the Act (43 U.S.C. 1352). This part supplements the procedures and requirements contained* * *."

Section 252.2 Definitions

Several respondents recommended that the definition of "affected State" be more tightly defined. Adoption of the definition of "affected State" proposed by notice in the Federal Register of June 7, 1978 (43 FR 24710), was recommended by some respondents. We have not adopted this recommendation. The answer to the question of whether a State is an affected State under the criteria established under section 2(f) of the OCS Lands Act, as amended, depends upon the proposed OCS activities and the location and significance of onshore activities relating to those OCS activities. No further action will be taken to finalize the notice published June 7, 1978, at 43 FR 24710 which tentatively identified "affected States." The identification of "affected States" will be determined on a case-by-case basis by the Director or the Director's designee.

A number of respondents requested the development of a definition for "affected local government" and a revision in the proposed definition of "area adjacent to a State."

The new definition of "affected local government" reflects the congressional intent to provide Governors of affected States with a degree of discretion in the identification of affected local governments. The new definition of "area adjacent to a State" was taken from paragraph 4(a)(2) of the OCS Lands Act.

We have adopted the suggestion of one respondent by expanding § 252.2(l) and (m) to recognize that "cross sections" as well as maps are a common form in which "interpreted geological information" and "interpreted geophysical information" are presented.

Section 252.3. Oil and Gas Data and Information to be Provided for Use in the OCS Oil and Gas Information Program

A number of respondents indicated that the protection afforded to permittees and lessees under the provisions of section 26(a)(1)(B) must also be applicable to interpretations of geological and geophysical information submitted under the requirements of 30 CFR Part 250, and that the provisions of §252.3(a) should be broadened to more closely track the language of the Act. We have adopted this recommendation.

One respondent suggested that § 252.3(a) be modified to require that copies of the data, information, interpretations, etc., be provided to the Director on a regular and timely basis. This recommendation has not been adopted. We believe that these regulations when read in conjunction with the ongoing programs of the Geological Survey, provide the Director continuous and timely access to the data and information needed to protect the national interest and to carry out the Survey's programmatic responsibilities without undue burden on either the Director's staff or the industry. If all data and information were required to be routinely submitted to the Director, the volume of unnecessary data and information that would be submitted would inundate the offices of the Geological Survey. Incorporation of such a requirement in the regulations in Part 252 would also require the Geological Survey to reimburse the lessees or permittees for the unneeded data and information. The flood of unneeded data and information would severely strain the funds that the Survey has available for obtaining needed data and information and to carry out its responsibilities.

A number of respondents suggested simplification of the language of § 252.3(b). This recommendation has not been adopted. The suggested language failed to distinguish between data or information provided by a lessee or a permittee for use in the OCS Oil and Gas Information Program; the data or information provided by lessees to meet obligations under their leases and the requirements of 30 CFR Part 250; and data and information provided by permittees as an obligation of their permits and the requirements of 30 CFR Part 251. The language of § 252.3(b) has been modified to more clearly indicate that reimbursement for data and information will be made only when reimbursement is requested by a lessee or permittee.

One respondent recommended that the regulations clearly state that the processing work of a lessee or permittee would take precedence over a request for data and information by the Director. This suggestion has not been adopted. The inclusion of such a provision could effectively preclude the Director from timely receiving needed data or information.

Several respondents expressed concern that the requirements of § 252.3(c) would not allow sufficient time for the lessee or permittee to comply with a request for data or information. Several alternative provisions were suggested that would relax the strict requirement for compliance within 30 days. It was recognized that a situation may develop that would preclude a lessee or permittee from providing requested data or information within 30 days. Subsection 252.3(c) has been modified to permit the Director to authorize a compliance time greater than 30 days when such action is warranted.

A number of respondents recommended that § 252.3(d) be modified to assure that permittees and lessees are afforded an opportunity to object before the Director exercises the right to disclose data and information to an independent contractor for processing. Several also recommended tighter contractual constraints on the uses that an independent contractor could make of the data or information so acquired. The principal concern expressed was the desire to assure the protection of the competitive position of lessees and permittees who provide data and information to the Director. New language has been incorporated into the regulations to address these concerns. The modified language requires the Director to notify, when practicable, the lessee or permittee who provided the data or information of the intent to disclose that data or information to an independent contractor or agent. It also affords the permittee or lessee a period of not less than 5 working days within which to provide the Director with comments on the intended action. Under the modified language the contractor is prohibited from making any use of the data or information other than that provided in the contract for reproduction, processing, reprocessing, or interpretation of the data or information. It also provides that contracts between the Geological Survey and independent contractors will be available to the lessee or permittee for inspection. The new language makes it clear that unauthorized "use" of data or information is on a par with unauthorized disclosure.

The respondents who suggested simplification of § 252.3(b) also suggested that the provisions of § 252.3(e) be simplified. This suggestion has not been adopted because the language of the provision proposed by the respondent does not adequately address the various contingencies set forth in section 26(a)(1)(C) of the Act.

Another respondent recommended that the reimbursement provisions of § 252.3(e) include the costs of a lessee or permittee that are due to special security measures used by the lessee or permittee to protect the confidential nature of data or information requested for use in the OCS Oil and Gas Information Program. This

suggestion has not been adopted. The security practices and procedures which a lessee or permittee employs are a private matter and cannot be permitted to increase the Government's costs of obtaining information. In the event the security practices and procedures which a lessee or permittee uses to protect data or information from disclosure results in the increased cost for compliance with the controlling regulations, that cost is properly borne by the lessee or permittee.

Subsection 252.3(e) also drew a number of comments from respondents who recommended that a time limit be placed upon the subsequent sale of information which could trigger a refund to the United States. Those recommendations have been adopted. Paragraphs 252.3(e)(1) and (4) have also been modified to require that requests for reimbursement be made within 60 days of the delivery of data or information requested for use in the OCS Oil and Gas Information Program. The request for reimbursement must include a breakdown of the costs to allow identification of reproduction costs, processing costs, and reprocessing costs.

Section 252.4. Summary Report to Affected States

Several respondents pointed out that section 26(b)(2) of the Act, as amended (43 U.S.C. 1352), described the Summary Report as a summary designed to assist in planning for "onshore" impacts of offshore oil and gas activities. These respondents recommended deletion of the references to planning for the "nearshore" impacts (§ 252.4(a)) and the inclusion of the general location of "nearshore" facilities (paragraph 252.4(a)(4)). We have adopted this recommendation to the extent that we have deleted the reference to planning for the "nearshore" impacts found in the first sentence of § 252.4(a) to more closely track the language of the law. We retained the reference to "nearshore" facilities in § 252.4(a)(4) to reflect that the Summary Report will contain information relating to oil and gas facilities located nearshore. Information regarding nearshore facilities is necessary to assist State and local governments in their planning processes.

The second sentence of § 252.4(a) has been modified to reflect the progress made since Part 252 was issued in January 1978. The new language also reflects the fact that the nature, scope, content, and timing of Summary Reports are subject to change. The modified language recognizes a continuing need for the Director to consult with affected States and other interested parties to review and revise, as appropriate, the nature, scope, content, and timing of Summary Reports.

Several respondents suggested that the listing of those with whom the Director may consult should specifically include permittees and lessees. This suggestion was not adopted. The phrase "other interested parties" includes permittees and lessees.

A number of respondents expressed the belief that the provisions of § 252.4(a) do not adequately reflect the protection of data and information from disclosure provided in section 26(d)(1)(B) of the Act. This concern has been addressed by the addition of specific language which indicates that Summary Reports are not to contain data or information which would unduly damage the competitive position of the lessee or permittee who provided the data or information.

Two respondents recommended that § 252.4(a) be modified to show that the Summary Report will be made available "to affected State agencies designated by the Governor." This change has not been adopted. The provision "* * * shall make available to affected States * * *" does not limit the availability of the Summary Report. The Summary Report is to be available to agencies of State and local governments and is to be publicly obtainable by interested parties on an equal basis.

One respondent suggested incorporation of Summary Reports into the Secretary's Annual Report to Congress and that § 252.4(a)(1) be modified to require the inclusion of information on the sulphur content of oil together with a breakdown of gas resources on the basis of unassociated gas and gas associated with oil. These recommendations have not been adopted. Congress did not indicate a wish to have Summary Reports included as part of the Annual Report required under section 15 of the Act, and the information maintained on resources does not include an estimate of the sulphur content of oil or a breakdown showing volumes of gas associated with oil and unassociated gas.

A respondent's recommendation that § 252.4 (a)(1) be modified to show that Summary Reports will include data and information on areas which the Secretary "has leased" has been adopted to better track the language of the statute.

The recommendation that § 252.4(a)(1) be modified to require identification of the most promising oil-bearing structures has not been adopted. The identification of "promising" structures would be highly speculative at best.

Another respondent's recommendation that § 252.4(a)(2) be expanded to include the magnitude and timing of exploration activities was not adopted. Plans for exploration activities are extremely fluid by nature. A timetable of exploration activities prepared for inclusion in a Summary Report would be out of date before it could be used effectively in a State or local government's planning process.

A respondent's recommendation that § 252.4(a) (3) be modified to list tankers as a means of transportation has been adopted. However the

term "vessels" was used instead of "tankers" to better conform to the language of the Act.

The recommendation that a new § 252.4(a)(5) be added to require the inclusion of a discussion of labor requirements and employment has not been adopted. This information will be provided to affected States in the environmental reports submitted in accordance with the requirements of 30 CFR 254.34.

One respondent's recommendation that § 252.4 (b) be modified to require issuance and revision of Summary Reports on a specified timetable has not been adopted. Subsection 252.4(a) makes it clear that Summary Reports may vary as to nature, scope, content, and timing. Thus there will not be a specific single timetable for updating all Summary Reports.

Section 252.5. Information to be Available to Affected States

Section 252.5 has been revised to conform to the provisions of 43 CFR 3300.2. This change is intended to eliminate confusion regarding the nature of the index of information, i.e., the index is a single document prepared jointly by the Bureau of Land Management and the Geological Survey. The modified section also incorporates modifications adopted in response to comments and recommendations received from interested parties.

The recommendation that the regulations indicate that the Geological Survey will disclose the identity of parties making tract nominations when release of that information would not compromise the parties' competitive positions has not been adopted. The regulations in 30 CFR Part 252 relate to the portion of the OCS Oil and Gas Information Program that is administered by the Geological Survey. The information relating to the identity of parties making nominations is subject to the control of the Bureau of Land Management. Release of that information is properly governed by regulations in 43 CFR Part 3300.

The recommendation that the index be made available on a semiannual basis to agencies designated by the governors of affected States has not been adopted. The index of information will be available to those agencies and others on a continuing basis.

A number of respondents recommended that § 252.5 be expanded to include provisions protecting data and information from disclosure when disclosure would unduly damage the competitive position of the lessee or permittee. This recommendation has not been adopted because the index will not contain privileged or proprietary data or information. However, since a new § 252.5(b) has been added under which recipients of the index can request copies of any information listed in the index, language has been added to indicate that privileged and proprietary data and information shall not be provided.

The recommendation that agencies other than the Geological Survey be listed in § 252.5 has not been adopted. The development and maintenance of the index is a time consuming and difficult task that the Department has undertaken without an increase in staffing or funding. The Department of the Interior cannot commit itself to the preparation of an all-inclusive listing of documents produced by and available through other elements of the Federal Government such as EPA, NOAA, and OCZM.

Section 252.6. Freedom of Information Act Requirements

Proposed § 252.6 has been modified only to the extent necessary to adopt a respondent's recommendation that the Director make data and information available in accordance with the requirements and "subject to the limitations" of the Freedom of Information Act (5 U.S.C. 552).

A number of respondents recommended that § 252.6 be modified in ways that would give lessees and permittees more control over disclosure of information, these recommendations have not been adopted. The Director must be able to effectively and efficiently carry out the responsibilities placed on Federal officials by the Freedom of Information Act.

Section 252.7. Privileged and Proprietary Data and Information To Be Made Available to Affected States

Many respondents recommended that the provisions of § 252.7(a)(1) which incorporate provisions of section 8(g) of the Act be incorporated into the regulations governing Oil and Gas and Sulphur operations in the Outer Continental Shelf (30 CFR Part 250) and Geological and Geophysical (G & G) Exploration of the OCS (30 CFR Part 251). The adoption of these recommendations results in the transfer of the provisions of § 252.7(a)(1) (i) and (ii) to Parts 250 and 251 and the identification of § 252.7(a)(1) (iii) as § 252.7(a). The text of § 252.7(a) has been modified to track the language of the Act (section 26(d)(2)--43 U.S.C. 1352). This change is intended to clarify the mandate of the Act that no "inspection shall take place prior to the sale of a lease covering the area in which such activity was conducted." This language more clearly specifies the constraints on a State official's right to inspect or have access to privileged information.

Two respondents recommended that § 252.7(a) be modified to allow the Governor of an affected State to designate more than one State official to inspect privileged or proprietary data or information. These recommendations have not been adopted. Section 26(d)(2) of the Act (43 U.S.C. 1352) clearly indicates that "* * *

the Governor of any affected State may designate an appropriate State official to inspect * * * privileged information." The nature of the penalties placed on unauthorized disclosure of proprietary information by a State or Federal official demonstrates Congress' intent that data and information made available for inspection by officials of affected States is to be made available in a manner which provides protection for the confidentiality of such information.

Many respondents pointed out that the special privilege allowing the Governor of an affected State the opportunity to designate an appropriate State official to inspect privileged or proprietary data or information does not carry with it the right or privilege to transmit or physically receive copies of such data or information without the consent of the lessee or permittee who provided the data or information. Subparagraphs 252.7(a)(2)(i) and (ii) state that no privileged or proprietary data or information will be transmitted to any affected State unless the lessee or permittee who provided the privileged or proprietary data or information agrees in writing to the transmittal of the data or information.

One respondent recommended that the Director be required to give notice to lessees or permittees before privileged or proprietary data or information is released to a Governor's designee. This recommendation has not been adopted. The right to inspect does not carry with it a right to reproduce or copy. In those instances under Part 252 where data or information will be transmitted pursuant to § 252.7 (a)(4), the lessees and/or permittees will have consented to the transmittal of the data or information.

A number of respondents recommended the addition of a requirement that a Governor obtain an opinion from the State's Attorney General that, under the State's law, the Governor is authorized to enter into the written agreement called for in § 252.7(a)(3), and that such an agreement will be binding upon the State and its employees. This recommendation has not been adopted. It will be the responsibility of the Department of the Interior's Solicitor to assure that each agreement between the Department of the Interior and a Governor of an affected State provides the required assurances mandated by Congress for the protection of privileged and proprietary data and information.

One respondent recommended that the regulations governing the OCS Information Program should clearly provide that proprietary and confidential information deleted from OCS exploration plans and development and production plans will be available for State inspection. That respondent also recommended that State coastal zone management agency officials be accorded special access to that information. These recommendations have not been adopted. An appropriate State official may inspect the deleted information relating to leased areas in areas adjacent to the State pursuant to section 26(d)(2) of the Act. The law does not permit recognition of a special right of inspection in a State's coastal zone management agency. The Governor may designate an official of the State's coastal zone management agency as the State's authorized official to inspect privileged and proprietary data and information pursuant to subsection 26(d)(2) of the Act.

Finally, a respondent recommended that § 252.7(b) be expanded to incorporate an opportunity for a lessee or permittee to seek remedial action at the agency level in lieu of requiring the lessee or permittee to proceed directly into the courts. This recommendation has not been adopted. The Department knows of no intermediate remedial action that is available to a lessee or permittee once privileged or proprietary data or information has been revealed.

AUTHORS

Thomas McCloskey, Office of the Assistant Secretary--Energy and Minerals, U.S. Department of the Interior (202/343-4457); and Gerald D. Rhodes, Geological Survey, U. S. Department of the Interior (703/860-7531).

ENVIRONMENTAL IMPACT AND REGULATORY ANALYSIS

The Department of the Interior has determined that the revision of the regulations in 30 CFR Part 252, in accordance with this notice, is not a major Federal action significantly affecting the quality of the human environment and will not require preparation of an environmental impact statement. The Department has also determined that this notice of final rule does not require preparation of a regulatory analysis under Executive Order 12044 and implementing regulations 43 CFR Part 2.

JOAN M. DAVENPORT,
Assistant Secretary of the Interior

JULY 25, 1979

2. Regulations, 30 CFR 252, Oil and Gas Information Program, Title 30 CFR 252, revised as of July 1, 1980.

AUTHORITY: Outer Continental Shelf Lands Act, 43 U.S.C. 1331 et seq., as amended, Pub. L. 95-372; Freedom of Information Act (5 U.S.C. 552).

SOURCE: 44 FR 46408, Aug. 7, 1979, unless otherwise noted.

§ 252.1 Purpose.

The purpose of this part is to implement the provisions of section 26 of the Act (43 U.S.C. 1352). This part supplements the procedures and requirements contained in parts 250 and 251 of this chapter and provides procedures and requirements for the submission of oil and gas data and information resulting from exploration, development, and production operations on the Outer Continental Shelf (OCS) to the Director, Geological Survey. In addition, this part establishes procedures for the Director to make available certain information to the Governors of affected States and, upon request, to the executives of affected local governments in accordance with the provisions of the Freedom of Information Act and the Act.

§ 252.2 Definitions.

When used in the regulations in this part, the following terms shall have the meanings given below:

(a) "Act" refers to the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 et seq.).

(b) "Affected local government" means the principal governing body of a locality which is in an affected State and is identified by the Governor of that State as a locality which will be significantly affected by oil and gas activities on the OCS.

(c) "Affected State" means, with respect to any program, plan, lease sale, or other activity, proposed, conducted, or approved pursuant to the provisions of the Act, any State:

(1) The laws of which are declared, pursuant to section 4(a)(2)(A) of the Act, to be the law of the United States for the portion of the OCS on which such activity is, or is proposed to be, conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or installations and other devices permanently, or temporarily attached to the seabed;

(3) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment which was extracted from the OCS and transported directly to such State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Director as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the OCS; or

(5) In which the Director finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oilspill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

(d) "Analyzed geological information" means data collected under a permit or a lease which have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analyses, laboratory analyses of physical and chemical properties, logs or charts of electrical, radioactive, sonic, and other well logs, and descriptions of hydrocarbon shows or hazardous conditions.

(e) "Area adjacent to a State" means that portion of the OCS which would be within the area of a State if the State's boundaries were extended seaward to the outer margin of the OCS.

(f) "Data" means facts and statistics or samples which have not been analyzed or processed.

(g) "Development" means those activities which take place following discovery of oil or natural gas in paying quantities, including geophysical activity, drilling, platform construction, and operation of all onshore support facilitiies, and which are for the purpose of ultimately producing the oil and gas discovered.

(h) "Director" means the Director of the Geological Survey of the U. S. Department of the Interior or a designee of the Director.

(i) "Exploration" means the process of searching for oil and natural gas, including: (1) geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of such oil or nat-

ural gas, and (2) any drilling, whether on or off known geological structures, including the drilling of a well in which a discovery of oil or natural gas in paying quantities is made and the drilling of any additional delineation well after such discovery which is needed to delineate any reservoir and to enable the lessee to determine whether to proceed with development and production.

(j) "Governor" means the Governor of a State, or the person or entity designated by, or pursuant to, State law to exercise the powers granted to a Governor pursuant to the Act.

(k) "Information," when used without a qualifying adjective, includes analyzed geological information, processed geophysical information, interpreted geological information, and interpreted geophysical information.

(l) "Interpreted geological information" means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of data and analyzed geological information.

(m) "Interpreted geophysical information" means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

(n) "Lease" means any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, oil or natural gas, or the land covered by such authorization, whichever is required by the context.

(o) "Lessee" means the party authorized by a lease, or an approved assignment thereof, to explore for and develop and produce the leased deposits in accordance with the regulations in Part 250 of this chapter, including all parties holding such authority by or through the lessee.

(p) "Outer Continental Shelf (OCS)" means all submerged lands which lie seaward and outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (67 Stat 29) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(q) "Permittee" means the party authorized by a permit issued pursuant to Part 251 of this chapter to conduct activities on the OCS.

(r) "Processed geophysical information" means data collected under a permit or a lease which have been processed. Processing involves changing the form of data so as to facilitate interpretation. Processing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

(s) "Production" means those activities which take place after the successful completion of any means for the removal of oil or natural gas, including such removal, field operations, transfer of oil or natural gas to shore, operation monitoring, maintenance, and workover drilling.

(t) "Secretary" means the Secretary of the Interior or a designee of the Secretary.

§ 252.3 Oil and gas data and information to be provided for use in the OCS Oil and Gas Information Program.

(a) Any permittee or lessee engaging in the activities of exploration for, or development and production of, oil and gas on the OCS shall provide the Director access to all data and information obtained or developed as a result of such activities, including geological data, geophysical data, analyzed geological information, processed and reprocessed geophysical information, interpreted geophysical information, and interpreted geological information. Copies of these data and information and any interpretation of these data and information shall be provided to the Director upon request. No permittee or lessee submitting an interpretation of data or information, where such interpretation has been submitted in good faith, shall be held responsible for any consequence of the use of or reliance upon such interpretation.

(b)(1) Whenever a lessee provides any data or information, at the request of the Director and specifically for use in the OCS Oil and Gas Information Program, in a form and manner of processing which is utilized by the lessee in the normal conduct of business, the Director shall pay the reasonable cost of reproducing the data and information if the lessee requests reimbursement. The cost shall be computed and paid in accordance with the applicable provisions of paragraph (e)(1) of this section.

(2) Whenever a permittee provides any data or information, at the request of the Director and specifically for use in the OCS Oil and Gas Information Program, in a form and manner of processing utilized by the permittee in the normal conduct of business, the Director shall pay the permittee the reasonable cost of reproducing the requested data and information if the permittee requests reimbursement. The Director shall pay, at the lowest rate available to any purchaser for processing the requested data and information, the costs attributable to such processing. The cost is to be computed and paid in accordance with the applicable provisions of paragraph (e)(3) of this section.

(3) Whenever a lessee or permittee provides any data or information, at the request of the Director and specifically for use in the OCS Oil and Gas Information Program, in a form and manner of processing not normally utilized by the lessee or permittee in the normal conduct of business, the Director shall pay the lessee or permittee, if the lessee or permittee requests reimbursement, the reasonable cost of processing and reproducing the requested data

and information. The cost is to be computed and paid in accordance with the applicable provision of paragraph (e)(2) of this section.

(c) Data or information requested by the Director shall be provided as soon as practicable, but not later than 30 days following receipt of the Director's request, unless for good reason, the Director authorizes a longer time period for the submission of the rquested data or information.

(d) The Director reserves the right to disclose any data or information acquired from a a lessee or permittee to an independent contractor or agent for the purpose of reproducing, processing, reprocessing, or interpreting such data or information. When practicable, the Director shall notify the lessee(s) or permittee(s) who provided the data or information of the intent to disclose the data or information to an independent contractor or agent. The Director's notice of intent will afford the permittee(s) or lessee(s) a period of not less than 5 working days within which to comment on the intended action. When the Director so notifies a lessee or permittee of the intent to disclose data or information to an independent contractor or agent, all other owners of such data or information shall be deemed to have been notified of the Director's intent. Prior to any such disclosure, the contractor or agent shall be required to execute a written commitment not to disclose any data or information to anyone without the express consent of the Director, and not to make any disclosure or use of the data or information other than that provided in the contract. Contracts between the Geological Survey and independent contractors shall be available to the lessee(s) or permittee(s) for inspection. In the event of any unauthorized use or disclosure of data or information by the contractor or agent, or by an employee thereof, the responsible contractor or agent or employee thereof shall be liable for penalties pursuant to section 24 of the Act.

(e)(1) After delivery of data or information in accordance with paragraph (b)(1) of this section, and upon receipt of a request for reimbursement and a determination by the Director that the requested reimbursement is proper, the lessee shall be reimbursed for the cost of reproducing the data or information at the lessee's lowest rate or at the lowest commercial rate established in the area, whichever is less. Requests for reimbursement must be made within 60 days of the delivery date of the data or information requested under paragraph (b)(1) of this section.

(2) After delivery of data or information in accorance with paragraph (b)(3) of this section, and upon receipt of a request for reimbursement and a determination by the Director that the requested reimbursement is proper, the lessee or permittee shall be reimbursed for the cost of processing or reprocessing and of reproducing the requested data or information. Requests for reimbursement must be made within 60 days of the delivery date of the data or information and shall be for only the costs attributable to processing or reprocessing and reproducing, as distinguished from the costs of data acquisition.

(3) After delivery of data or information in accordance with paragraph (b)(2) of this section, and upon receipt of a request for reimbursement and a determination by the Director that the requested reimbursement is proper, the permittee shall be reimbursed for the reasonable costs attributable to reproducing the data and information and, also, for processing or reprocessing costs at the lowest rate at which the processed or reprocessed information is made available by the permittee to any purchaser. The permittee shall be reimbursed on the basis of the maximum discount rate offered by the permittee with respect to the requested data or information regardless of the quantity of data or information requested by the Director. The permittee shall refund to the United States any amount paid by the United States in excess of the amount paid by any other purchaser of the same processed information, unless the lower amount is paid by a purchaser in connection with a subsequent purchase made more than 2 years after the date that the data or information was delivered to the Director.

(4) Requests for reimbursement are to contain a breakdown of costs in sufficient detail to allow separation of reproduction, processing, and reprocessing costs from acquisition and other costs.

(f) Each Federal Department or Agency shall provide the Director with any data which it has obtained pursuant to section 11 of the Act and any other information which may be necessary or useful to assist the Director in carrying out the provisions of the Act.

§ 252.4 Summary Report to affected States.

(a) The Director, as soon as practicable after analysis, interpretation, and compilation of oil and gas data and information developed by the Geological Survey or furnished by lessees, permittees, or other government agencies, shall make available to affected States and, upon request, to the executive of any affected local government, a Summary Report of data and information designed to assist them in planning for the onshore impacts of potential OCS oil and gas development and production. The Director shall consult with affected States and other interested parties to define the nature, scope, content, and timing of the Summary Report. The Director may consult with affected States and other interested parties regarding subsequent revisions in the definition of the

nature, scope, content, and timing of the Summary Report. The Summary Report shall not contain data or information which the Director determines is exempt from disclosure in accordance with this part. The Summary Report shall not contain data or information the release of which the Director determines would unduly damage the competitive position of the lessee or permittee who provided the data or information which the Director has processed, analyzed, or interpreted during the development of the Summary Report. The Summary Report shall include:

(1) Estimates of oil and gas reserves; estimates of the oil and gas resources that may be found within areas which the Secretary has leased or plans to offer for lease; and when available, projected rates and volumes of oil and gas to be produced from leased areas;

(2) Magnitude of the approximate projections and timing of development, if and when oil or gas, or both, is discovered;

(3) Methods of transportation to be used, including vessels and pipelines and approximate location of routes to be followed; and

(4) General location and nature of near-shore and onshore facilities expected to be utilized.

(b) When the Director determines that significant changes have occurred in the information contained in a Summary Report, the Director shall prepare and make available the new or revised information to each affected State, and, upon request, to the executive of any affected local government.

§ 252.5 Information to be made available to affected States.

(a) The Director in conjunction with the Director of the Bureau of Land Management shall prepare an index of OCS Information (see 43 CFR 3300.2). The index shall list all relevant actual or proposed programs, plans, reports, environmental impact statements, nominations information, environmental study reports, lease sale information, and any similar type of relevant information, including modifications, comments, and revisions prepared or directly obtained by the Director under the Act. The index shall be sent to affected States and, upon request, to any affected local government. The public shall be informed of the availability of the index.

(b) Upon request, the Director shall transmit to affected States, affected local governments, and the public a copy of any information listed in the index which is subject to the control of the Geological Survey, in accordance with the requiremets and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and implementing regulations. The Director shall not transmit or make available any information which he determines is exempt from disclosure in accordance with this part.

§ 252.6 Freedom of Information Act requirements.

(a) The Director shall make data and information available in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 52), the regulations contained in 43 CFR Part 2 (Records and Testimony), the requirements of the Act, and the regulations contained in 30 CFR Part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf) and 30 CFR Part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf).

(b) Except as provided in § 252.7 or in Parts 250 and 251 of this chapter, no data or information determined by the Director to be exempt from public disclosure under paragraph (a) of this section shall be provided to any affected State or be made available to the executive of any affected local government or to the public unless the lessee, or the permittee and all persons to whom such permittee has sold such data or information under promise of confidentiality, agree to such action.

§ 252.7 Privileged and proprietary data and information to be made available to affected States.

(a)(1) The Governor of any affected State may designate an appropriate State official to inspect, at a regional location which the Director shall designate, any privileged or proprietary data or information received by the Director regarding any activity in an area adjacent to such State, except that no such inspection shall take place prior to the sale of a lease covering the area in which such activity was conducted.

(2)(i) Except as provided for in 30 CFR 250.4 and 251.14, no privileged or proprietary data or information will be transmitted to any affected State unless the lessee who provided the privileged or proprietary data or information agrees in writing to the transmittal of the data or information.

(ii) Except as provided for in 30 CFR 250.4 and 251.14, no privileged or proprietary data or information will be transmitted to any affected State unless the permittee and all persons to whom the permittee has sold the data or information under promise of confidentiality agree in writing to the transmittal of the data or information.

(3) Knowledge obtained by a State official who inspects data or information under paragraph (a)(1) or who receives data or information under paragraph (a)(2) of this section shall be subject to the requirements and limitations of the Freedom of Information Act (5 U.S.C. 552), the regulations contained in 43 CFR Part 2 (Records and Testimony), the Act (92 Stat. 629), the regulations contained in 30 CFR Part 250

(Oil and Gas and Sulphur Operations in the Outer Continental Shelf), the regulations contained in 30 CFR Part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf), and the regulations contained in this Part 252 (Outer Continental Shelf Oil and Gas Information Program).

(4) Prior to the transmittal of any privileged or proprietary data or information to any State, or the grant of access to a State official to such data or information, the Secretary shall enter into a written agreement with the Governor of the State in accordance with section 26(e) of the Act (43 U.S.C.1352). In that agreement the State shall agree as a condition precedent to receiving or being granted access to such data or information to: (i) protect and maintain the confidentiality of privileged or proprietary data and information in accordance with the laws and regulations listed in paragraph (a)(3) of this section; (ii) waive the defenses as set forth in paragraph (b)(2) of this section; and (iii) hold the United States harmless from any violations of the agreement to protect the confidentiality of privileged or proprietary data or information by the State or its employees or contractors.

(b)(1) Whenever any employee of the Federal Government or of any State reveals in violation of the Act or of the provisions of the regulations implementing the Act, privileged or proprietary data or information obtained pursuant to the regulations in this chapter, the lessee or permittee who supplied such information to the Director or any other Federal official, and any person to whom such lessee or permittee has sold such data or information under the promise of confidentiality, may commence a civil action for damages in the appropriate district court of the United States against the Federal Government or such State, as the case may be. Any Federal or State employee who is found guilty of failure to comply with any of the requirements of this section shall be subject to the penalties described in section 24 of the Act (43 U.S.C. 1350).

(2) In any action commenced against the Federal Government or a State pursuant to paragraph (b)(1) of this section, the Federal Government or such State, as the case may be, may not raise as a defense any claim of sovereign immunity, or any claim that the employee who revealed the privileged or proprietary data or information which is the basis of such suit was acting outside the scope of the person's employment in revealing such data or information.

(c) If the Director finds that any State cannot or does not comply with the conditions described in the agreement entered into pursuant to paragraph (a)(4) of this section, the Director shall thereafter withhold transmittal and deny access for inspection of privileged or proprietary data or information to such State until the Director finds that such State can and will comply with those conditions.

[illegible] the Secretary [illegible]

[illegible]

(iii) Methods of transportation [illegible] pipelines and [illegible] to the following; and

(iv) General location and nature of onshore and offshore facilities expected to be utilized.

(2) When the Director determines that any significant changes have occurred in the information contained in a summary report, the Director shall prepare and make available [illegible] information [illegible] to affected States and, upon request, [illegible] any affected local government.

§ 252.5 Information to be made available to affected States.

(a) The Director, in cooperation with the Director of the Bureau of Land Management, shall prepare an index of all information [illegible] the Act. The index shall list [illegible] actual or proposed programs, plans, reports, environmental impact statements, [illegible] information, environmental study reports, lease sale information, and any similar type of relevant information, including modifications, comments, and revisions prepared or obtained by the Director under the Act. The index shall be sent to affected States and, upon request, to any affected local government. The public shall be informed of the availability of the index.

(b) Upon request, the Director shall [illegible]

[illegible] in the Outer Continental Shelf), the regulations contained in 30 CFR Part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf) [illegible]

(4) [illegible]

[illegible] with the Governor of the State [illegible] with section 26(e) of the Act [illegible]

[illegible] confidentiality of privileged or proprietary data or information by the State or its employees or contractors.

(b)(1) Whenever any employee of the Federal Government or of any State reveals in violation of this Act [illegible] the regulations [illegible]

[illegible] of the United States against the Federal Government [illegible] the Act (43 U.S.C. [illegible])

(2) [illegible]

M. 30 CFR 290, Appeals Procedures, Title 30 CFR, revised as of July 1, 1979.

PART 290 - APPEALS PROCEDURES

Sec.
290.1 Scope.
290.2 Who may appeal.
290.3 Appeals to Director.
290.4 Oral argument.
290.5 Time limitations.
290.6 Appeals to the Commissioner of Indian Affairs.
290.7 Appeals to the Board of Land Appeals.

AUTHORITY: R.S. 463, 25 U.S.C. 2; R.S. 465, 25 U.S.C. 9; sec. 32, 41 Stat. 450, 30 U.S.C. 189; sec. 5, 44 Stat. 1058, 30 U.S.C. 285; sec. 10, 61 Stat. 915, 30 U.S.C. 359; sec. 5, 6, 67 Stat. 464, 465, 43 U.S.C. 1334, 1335; sec. 24, 84 Stat. 1573, 30 U.S.C. 1023.

SOURCE: 38 CFR 10001, April 23, 1973, unless otherwise noted.

§ 290.1 Scope.

The rules and procedures set forth herein apply to appeals to the Director, Geological Survey (and the Commissioner of Indian Affairs when Indian lands are involved) from final orders or decisions of officers of the Conservation Division, Geological Survey, issued under authority of the regulations in chapter II of this title, 43 CFR part 23, 43 CFR subtitle B, chapter II, and 25 CFR part 177. This part also provides for the further right of appeal to the Board of Land Appeals in the Office of Hearings and Appeals, Office of the Secretary, from adverse decisions of the Director (and the Commissioner of Indian Affairs when Indian lands are involved) rendered under this part.

§ 290.2 Who may appeal.

Any party to a case adversely affected by a final order or decision of an officer of the Conservation Division of the Geological Survey shall have a right to appeal to the Director, Geological Survey, unless the decision was approved by the Secretary or the Director prior to promulgation.

§ 290.3 Appeals to Director.

(a) An appeal to the Director, Geological Survey, may be taken by filing a notice of appeal in the office of the official issuing the order or decision within 30 days from service of the order or decision. The notice of appeal shall incorporate or be accompanied by such written showing and argument on the facts and laws as the appellant may deem adequate to justify reversal or modification of the order or decision. Within the same 30-day period, the appellant will be permitted to file in the office of the official issuing the order or decision additional statements of reasons and written arguments or briefs.

(b) The officer with whom the appeal is filed shall transmit the appeal and accompanying papers to the Director, Geological Survey, with a full report and his recommendation on the appeal.

(c) The Director will review the record and render a decision in the case.

§ 290.4 Oral argument.

Oral argument in any case pending before the Director, Geological Survey, will be allowed on motion in the discretion of such officer and at a time to be fixed by him.

§ 290.5 Time limitations.

With the exception of the time fixed for filing a notice of appeal, the time for filing any document in connection with an appeal may be extended by the Director, Geological Survey. A request for an extension of time must be filed within the time allowed for filing of the document and must be filed in the same office in which the document in connection with which the extension is requested must be filed.

§ 290.6 Appeals to the commissioner of Indian Affairs.

The procedure for appeals under this part shall be followed for permits and leases on Indian land except that with respect to such permits and leases, the Commissioner of Indian Affairs will exercise the functions vested in the Director, Geological Survey.

§ 290.7 Appeals to the Board of Land Appeals.

Any party to a case adversely affected by a final decision of the Director, Geological Survey or the Commissioner of Indian Affairs under this part shall have a right of appeal to the Board of Land Appeals in the Office of Hearings and Appeals Office to the Secretary, in accordance with the procedures provided in 43 CFR, "Part 4, Department Hearings and Appeals Procedures."

N. 43 CFR 3300, Outer Continental Shelf Minerals Leasing and Rights-of-Way Management, Title 43 CFR, revised as of October 1, 1979, amended by: 45 FR 69174-75, October 17, 1980.

1. Preamble, 43 CFR 3300, Outer Continental Shelf Minerals Leasing and Rights-of-Way Granting Programs; 44 FR 38268, June 29, 1979.

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 2880 and 3300

Outer Continental Shelf Minerals Leasing and Rights-of Way Granting Programs

AGENCY: Bureau of Land Management, Interior.

ACTION: Final rulemaking.

SUMMARY: This final rulemaking implements the changes mandated in the Outer Continental Shelf Mineral Leasing and Rights-of-way Granting program administered by the Secretary of the Interior by the enactment of the Outer Continental Shelf Lands Act Amendments of 1978. The final rulemaking contains changes to make Part 3300 more readable as directed by Executive Order 12044, and rearranges the subparts to make the part easier to follow and understand. Finally, subpart 2883, (Part 2880) Rights-of-way on the Outer Continental Shelf, is being moved to Part 3300 in order to consolidate all Outer Continental Shelf programs in one part.

EFFECTIVE DATE: July 30, 1979.

ADDRESS: Any recommendations or comments on the final rulemaking should be sent to: Director (712), Bureau of Land Management, Department of the Interior, 1800 C Street, N.W., Washington, D.C. 20240.

FOR FURTHER INFORMATION CONTACT:

William J. Quinn (202) 343-8457 or Robert C. Bruce (202) 343-8735.

SUPPLEMENTARY INFORMATION: The proposed rulemaking on the Outer Continental Shelf Minerals Leasing and Rights-of-way Granting program was published in the Federal Register on February 1, 1979 (44 FR 6471). The proposed rulemaking invited comments for 60 days ending April 2, 1979. During the comment period, a total of 37 comments were received and considered. Thirteen comments came from companies interested in the Outer Continental Shelf, 12 came from State Governments, five from industry interest groups, three from environmental groups and four from Federal agencies.

Among the general comments were expressions that the rulemaking followed the requirements of the Outer Continental Shelf Lands Act Amendments of 1978 (43 U.S.C. 1331 et seq.). Several of the State comments also commended the Department of the Interior on its efforts to work with the States on this rulemaking and to incorporate provisions that facilitated the coordination of the Outer Continental Shelf program with the States. One comment was that the rulemaking was wordy and a large portion of it could be eliminated in keeping with the provisions of Executive Order 12044. However, most of the comments requested additional wording for the rulemaking, wording that made the final rulemaking longer than the proposed document.

Several of the comments expressed concern that the proposed rulemaking made no reference to the national policy section or the mandate in section 3 of the Outer Continental Shelf Lands Act Amendments to protect specific resources, such as fisheries or recreation. In response to these comments, a new section on policy was added to clarify the Bureau of Land Management's responsibilities and to include these references.

Several comments raised questions about the lack of reference in the rulemaking to the National Environmental Policy Act (42 U.S.C. 4321 et seq.), the Coastal Zone Management Act (16 U.S.C. 1451 et seq.), and protection of the environment mandated by the policy sections of the Outer Continental Shelf Lands Act Amendments. These comments were not only general but were made in reference to many sections of the proposed rulemaking. These three areas are, among others, areas of major concern to the Department of the Interior and the Bureau of Land Management in carrying out their responsibilities under the Outer Continental Shelf Lands Act, as amended. Not only are these responsibilities recognized and accepted, but the National Environmental Policy Act and many other statutes impose obligations on the Department and the Bureau at virtually every phase of the leasing and resource management process. For these reasons, it was not considered necessary to enumerate in every section of the rulemaking the legal obligations of the Department and the Bureau. This repetition of clearly accepted obligations would be redundant and lengthen the rulemaking.

A few comments stated that a section was needed in the rulemaking that outlined the responsibilities of each of the agencies involved in the mineral leasing program on the Outer Continental Shelf. The addition of a "responsibilities" section was not considered appropriate for inclusion in the text of the rulemaking which deals primarily with the role of the Bureau of Land Management. The Bureau's responsibilities are implicit in this rulemaking; the responsibilities of other agen-

cies in the leasing process are covered in their own rules. Some important responsibilities of other agencies are mentioned in the text as required for clarity, typically by cross-reference to other regulations or by citation of applicable laws. The responsibilities of the major Federal agencies participating in the process are outlined below.

Briefly, the Bureau of Land Management is the lead agency for the Outer Continental Shelf leasing process and is responsible for the issuance and maintenance of leases. The Bureau of Land Management also issues rights-of-way for the transportation of minerals through the Outer Continental Shelf. The Bureau of Land Management, along with the U. S. Geological Survey, is responsible for providing an index and summary of existing information on the Outer Continental Shelf to affected States.

The U. S. Geological Survey provides technical advice throughout the leasing process. The Geological Survey is responsible for supervising and regulating pre-lease exploration activity and post-lease exploration, development and production activities on the lease area. The Geological Survey also grants rights of use and easements on the Outer Continental Shelf.

The Department of Energy has responsibilities transferred from the Department of the Interior to issue regulations which relate to:

(1) fostering of competition for Federal leases;

(2) implementation of alternative bidding systems authorized for the award of Federal leases;

(3) implementation of diligence requirements for operations conducted on Federal leases;

(4) setting rates of production for Federal leases; and

(5) specific procedures, terms and conditions for the acquisition and disposition of Federal royalty interest taken in kind, except determination of value. The Department of Energy is afforded up to 30 days to review the final lease terms and conditions on all Outer Continental Shelf leases relative to the five functions cited above.

A number of comments expressed a desire for extensive cross-referencing to other laws in various sections of the rulemaking, especially the National Environmental Policy Act of 1969 (42 U.S.C. 4321 et seq.). These comments were not adopted, but a new section on cross-references 3300.0-6, was added to the final rulemaking which includes extensive cross-reference to other applicable regulations, including National Environmental Policy Act compliance.

Several comments suggested changes in the definitions used in the proposed rulemaking. After careful consideration of the suggested changes, it was decided to change the definition of the term "mineral" in order to remove an ambiguous reference. All of the other definitions track the language of the Outer Continental Shelf Lands Act Amendments and are sufficiently clear.

A suggestion was offered that section 3300.1 set the scale and availability of leasing maps and diagrams. The preparation of leasing maps and diagrams is an internal Bureau of Land Management procedure. Further, the scale of available maps and diagrams is subject to change and the Bureau should be permitted the broadest possible latitude in the preparation process.

A few comments on section 3300.1 questioned why withdrawal of areas of the Outer Continental Shelf as provided for in section 12(a) and (d) of the Act was not covered. The focus of withdrawal, e.g., for defense or any other purpose in the national interest, and the procedures for withdrawal are not appropriate for consideration in this rulemaking which deals with mineral leasing. However, deletion of tracts, for whatever reason, is specifically covered by the rulemaking.

A large number of comments were received on section 3300.2 indicating confusion as to the form, content, timing and distribution of information to the affected States. In reference to these comments, the wording of the section has been changed in an effort to clear up the confusion reflected in the comments.

The current policy of the Department of the Interior is to prepare a joint Bureau of Land Management--U. S. Geological Survey regional index of Outer Continental Shelf information. This index is widely distributed and is updated, as needed, so as to be of maximum use to the affected States and the public. This joint index lists those documents prepared and controlled by each agency so the user will be required to refer to only one list for all relevant information. Another change in section 3300.2 was the addition of language that emphasizes that information under the control of the Bureau of Land Management that is listed on the index, e.g., environmental statements or studies, lease sale data, etc., generally is information that is not protected by the Freedom of Information Act and will be released to the public upon request. Information under the control of the U. S. Geological Survey that is listed in the index is more likely to be proprietary and is subject to the U. S. Geological Survey regulations for the release of such data. The rulemaking makes it clear that the Bureau of Land Management cannot release protected data listed on the index under the control of the U. S. Geological Survey. The section also closely controls the release of proprietary data controlled by the Bureau of Land Management, namely the specific nominations of tracts made by industry. This expanded wording, which is in response to a sizable number of comments on this subject, should dispell doubts expressed in the comments about the release of protected information listed on the index.

The timing of the updating of the index drew a large number of comments. As was pointed out, the index must be current in order to be useful. The updating of the index is likely to vary greatly among regions according to the levels of leasing and development activity taking place in an area. Therefore, it is not practicable to set a definite timetable in the rulemaking for the updating of the index, as several comments suggested. The Department of the Interior will make every effort to keep the public fully informed of the availability of key documents through the use of local press releases, Federal Register notices and other means. Such notices will also be used to notify the public of the availability of an updated index, as was recommended by one comment.

Since the index is a public document that will receive broad distribution, the suggestions that its distribution be limited by the rulemaking were not adopted. Similarly, recommendations to restrict the distribution of information listed in the index could not be adopted. The Bureau of Land Management will, as required by law, honor all requests for information except that which is withheld under the Freedom of Information Act or information protected by the provisions of the Outer Continental Shelf Lands Act Amendments. The phrase "in conjunction with the USGS" was made a part of the section as recommended in one of the comments to clarify the intent to publish a single joint index for each region. The cross references to 30 CFR 250, 251 and 252 are retained to guide the readers of this rulemaking to companion regulations but do not imply that the Bureau of Land Management can release any information controlled by the U. S. Geological Survey.

A number of wording changes recommended in the comments were adopted to make section 3300.2 internally consistent. Finally, a recommendation to move section 3300.2 and make it a part of section 3313 Call for Nominations and Comments was not accepted because the information covered by section 3300.2 is much broader than that covered by a single pre-lease event in the leasing process.

Several comments were directed to section 3300.3. As was suggestd, wording from existing regulations on this subject was restored to the final rulemaking to make it clear that the extraction of helium will not be the cause for substantial delay in the delivery of natural gas. In order to clear up confusion about who determines reasonable compensation for losses, wording was added that the United States would make such determinations. However, comments that suggested that the Federal government should be made solely responsible for all risk, cost and expenses connected with the removal of helium were not adopted. The determination of those issues will be made on case-by-case basis when the United States exercises its option to extract helium.

In connection with section 3300.4 payments, comments suggesting that the section be deleted in favor of specific references to payments at each stage of the process which calls for a payment were not adopted. The suggested change would add a great deal of language to the rulemaking and not add much additional clarity.

One comment recommended the use of electronic fund transfer or Federal fund drafts as the required form of payment. While the merits of these systems are under discussion and the rulemaking is flexible enough to allow their use as methods of payment, a formal adoption of this recommendation cannot be made at this time. This recommendation is being considered as a separate issue. If these systems can be adapted to the OCS Leasing program they will be considered in a future amendment. There are many amounts of money collected under this program that are too small to be amenable to payment to either of these two systems.

Several comments, in addressing section 3313, suggested that the rulemaking include a commitment to publish the Call for Nominations and Comments for oil and gas lease sales in keeping with the current policy of the Department of the Interior to publish calls in the Federal Register and to announce them through press releases, this suggestion has been adopted and appropriate language added to the section.

A comment suggested additional State involvement in the preparation of the Call for Nominations and Comments. The wording of section 3313.1(a) was not changed. An additional layer of coordination efforts mandated by regulation would only serve to burden an already complicated pre-lease process. The affected States have ample opportunities for input to the very early leasing decision and sale design. Affected States are, by law and regulation, given the opportunity to review and comment on the 5-year leasing program which is now being developed and which will be reviewed annually and on the Call for Nominations, after it is issued. The intergovernmental planning program also allows continuous input by affected States to all phases of the leasing and lease management processes.

There were several suggestions to further describe the terms used in section 3313 of the rulemaking. In response, language has been added showing examples of the types of information the Director may request in the Call for Nominations and Comments. The Call requests "nominations", i.e., asks interested parties to nominate tracts they wish to be included in a lease sale for an area which has been designated as being potentially available for leasing. One suggestion was that "negative nominations" referred to in the Outer Continental Shelf Lands Act Amendments be explicitly included in the term "nominations" as it is used in this section. This is not the intent of

the Act. The Call requests nominations as well as "Comments" on potential environmental impacts and use conflicts in the area under consideration. The comments often identify areas or specific tracts which the individuals making comments feel should receive special concern or analysis, or which should be deleted from the sale area. The comment to delete a tract or tracts is what is referred to in the Act as a "negative nomination."

Nominations of tracts by the industry or States do not assure their selection for further analysis or ultimate inclusion in a lease sale. Comments, including the request to delete a tract, or so called "negative nominations" do not assure automatic deletion of a tract or tracts from the sale area.

Similarly, selection of tracts for further analysis does not assure their inclusion in any subsequent lease sale offering, nor does it mean they will be deleted for environmental or other reasons. In other words, it is the intention of the Bureau of Land Management to consider, during the Call and the tentative tract selection processes, all available information which might influence the recommendation of tracts for further environmental analysis. Such information includes, but is not limited to, multiple uses of the area, including fisheries, environmental and geological conditions, resource potential, and indications of interest. Tentative tract selection leads to recommendations by the Director to the Secretary of the tracts which should be further analyzed.

The term "recommendation", as it is used in the rulemaking, implies justification of the decision being recommended. This being true, it was not necessary to adopt a suggestion that language be added to the rulemaking requiring the Director to justify his recommendations.

As suggested by several comments, a new section 3313.2 has been added providing procedures for State consultation on tracts within three miles of a State's seaward boundary. Subpart 3314, tentative tract selection, has been given a new title and strengthened as a result of comments directed to it. First, a sentence has been added to section 3314.1(a) permitting the Director to include in the recommendation tracts not nominated. Second, another sentence has been added to the same section requiring the Director to consider environmental and all other relevant information before making recommendations on tract selection. For clarity, the section has been broken into two subsections, with the word "tentatively" to indicate that this stage is an interim designation of tracts to be further considered for leasing. Another change in subsection (b) was the addition of "local governments" to the list of agencies and individuals whose recommendations will be considered. Finally, a phrase has been included in subsection (b) requiring the Director not only to assess the impacts of leasing but also to develop appropriate measures to mitigate adverse impacts.

A new subsection (c) has been added to the section requiring the Director to inform the public as soon as possible of any tract additions or deletions that occur after the tentative selections have been made.

A suggestion that a public hearing be held before a tentative tract selection was not adopted since there is ample opportunity for public input associated with the Call for Nominations and Comments. An additional hearing would only burden the process without yielding any real benefit.

A suggestion that was not adopted was that a coordination process be written into section 3314 of the rulemaking. The language calls for consultation with other agencies that is designed to determine priorities and will vary with each tract selection process.

In connection with section 3314.2, a suggestion was made that the term "reasonable economic production unit" be defined. The term is used as a criterion for selecting tracts larger than 5760 acres. This decision will be made on a sale or tract basis.

The language of subpart 3315, lease sales, was changed in several instances in response to a number of comments. The titles of the first two sections were changed to more accurately reflect the contents of the sections.

Several comments suggested that affected States be directly involved in the development of lease stipulations and conditions. This suggestion could not be adopted since it would add another layer of consultation that is not warranted. Affected States are afforded an opportunity for continuous input into leasing decisions through the intergovernmental planning program. Further, State agencies are consulted while mitigating measures are being developed during the environmental analysis. Affected States have an opportunity to submit written comments on mitigating measures and may give testimony at hearings, during the public comment period. Finally, States are allowed 60 days to comment on the proposed notice of rule, which includes mitigating measures as part of the proposal.

Suggestions to significantly expand or restrict the involvement of affected States and to require consultation with local governments, the industry and the public, go beyond the intent of the Outer Continental Shelf Lands Act, as amended, and could not be accepted since the language of section 19 of the Act is quite specific on this point. For example, suggestions made to require the Secretary of the Interior to give the same weight to affected local government recommendations as to those from the Governors of affected States could not be adopted because of the very precise wording of section 19(c) of the Act. Similarly, the

scope of the recommendations by affected States and which the Secretary typically must accept is clearly spelled out in section 19(a) of the Act and cannot be expanded, as suggested, to cover comments on lease stipulations. This is not to imply, however, that Governors or any member of the public are in any sense prohibited from commenting on any part of the proposed notice or that any such comment will not be given due consideration.

Subsection (a) of section 3315.1 has been revised, as suggested, to define "mitigating measures" as including lease stipulations but does not spell out the issues which the stipulations might address, e.g., geologic hazards, etc. These issues are sale or tract specific and would not be appropriately the subject of a rulemaking that covers all sales. Another suggestion on this section was that industry be contacted to discuss the development of particularly unusual or extreme stipulations. While this suggestion was not adopted, it was felt to have merit and efforts will be made by the Department of the Interior, when appropriate, to elicit industry involvement in the development of stipulations that impose substantial burdens on the lessee.

Another suggestion of merit that was not added to section 3315.1 of the rulemaking dealt with the addition of a sale date in the proposed notice. While this is an item that is not appropriately included in a rulemaking there will be an attempt to publish a tentative sale date as part of the proposed notice to facilitate planning.

A new subsection (c) added to section 3315.1 outlines the publication procedure on a proposed notice of sale. The subsection also requires the notice to be sent to the Governor of any affected State at the same time it is published in the Federal Register. This subsection was added when it was discovered that the proposed rulemaking failed to include this requirement.

A suggested amendment to section 3315.2(b) was adopted by the addition of a new sentence to expand the provision relating to how a determination of national interest will be made and to reemphasize the Department of the Interior's commitment to developing resources consistent with the findings, purposes and policies of the Outer Continental Shelf Lands Act, as amended. For further clarity, subsection (b) was divided into two parts, with the second part becoming a new subsection (c). A recommendation to require the secretary to respond to the Governors' recommendations within 30 days was rejected as being too restrictive.

A new section 3315.3, Department of Energy review added to the regulations specifies the review process with the Department of Energy. This change was made in response to a suggestion that pointed out the importance of this mandated review.

Section 3315.4(b) was amended by the addition of a sentence pointing out that the suggested formats for bidder submissions and joint bidder's statements have been prepared and added to Part 3300 as appendices. This addition will be of assistance to those who are required to file the documents. A cutoff date for the use of multiple bidding submissions for statistical purposes was added to section 3315.4(e) to reflect the language of the Outer Continental Shelf Lands Act Amendments. The need for this date was indicated in several comments. An amendment that was suggested but not adopted was a request that the procedures for multiple bidding be spelled out in greater detail. The Department of the Interior will detail the procedures for use of the multiple bidding systems at the time a decision is made to use such systems.

Many minor wording changes to subpart 3316, Issuance of Leases, were made. Most of these changes were recommended in the comments and are designed to clarify the subpart. One major change was the addition of a sentence to section 3316(b) to include two provisions of the Outer Continental Shelf Lands Act Amendments relating to lease term. One suggestion to provide for a 10-year lease term for tracts when production technology is not available for the water depths involved was not accepted. Rather the statutory language was retained to allow the determination of the need for a longer lease term to be made on a sale-by-sale basis.

A number of comments requested that the reference to diligence requirements in section 3316.4(i) be expanded to include definitions, standards, hearing procedures, etc., or alternatively, be deleted until such definitions and procedures are available. While the expressed concerns are valid, the language of the subsection was not changed. The subsection necessarily draws the attention of potential bidders to the diligence provisions of the Act. The establishment of diligence requirements and the setting of production rates are the responsibility of the Department of Energy. The U. S. Geological Survey has the responsibility for setting deadlines for the submission of exploration and development plans, requirements which deal with diligence in the broad sense of the word. The U. S. Geological Survey has already surfaced exploration and development plan submission requirements in its proposed rulemaking, 30 CFR 250.34. There is movement, therefore, towards more precise definitions of the responsibilities of lessees to actively explore and develop offshore leases.

Several comments objected to the possibility of a potential bidder receiving a notice of disqualification just prior to a lease sale and wanted a 30- or 60-day notice period to be included. The language of the law prohibits submission of bids by a bidder found not to be diligent on other leases, without mention of a

specific period for notification prior to a sale. However, in practice, it is reasonable to expect that a potential bidder would have ample notice of possible disqualification because of the statutory requirement for notice and hearing. No change was made in the rulemaking.

Among other changes to section 3316.5 is the rearrangement of provisions to more closely follow the sequence of events in the issuing of leases. A suggestion to require bidders to submit an "add-on" bid to determine the winning high bid in case of a tie bid was not adopted since tie bids are rare. The procedure outlined is sufficient to handle the problem. Several comments objected to the reduced time allowed for execution of leases and payment of the balance of the cost bonus. The language was left to stand. The benefits to the Government far outweigh the inconvenience which successful joint bidders might experience in executing leases within the fifteen days allowed. Recommended language to further clarify what happens when the 15th day coincides with a holiday or weekend was not adopted because it was not needed. Standard practice recognized in the Government extends a deadline that falls on a holiday or weekend to the next working day.

Several suggestions on section 3316.5(i), renumbered (h), to require the payment of interest on deposits while bids are being considered were not accepted. The Outer Continental Shelf Lands Act Amendments clearly leaves this matter to the discretion of the Secretary of the Interior. However, the wording was changed to make interst provisions apply, again at the discretion of the Secretary, in cases where sale areas are withdrawn or restricted before leases are issued. The Department of the Interior is presently exploring, in consultation with the Treausry Department, procedures to pay interest on deposits.

Several comments asked what would happen if the Secretary of the Interior rejected a highest qualified bid upon the recommendation of the Attorney General after the antitrust review of the bids. This is a difficult question because it is current practice to hold only the highest bids and return all others. There has been no need to hold other bids because to date there has been no rejection of high bids because of the recommendation of the Attorney General. However, this is recognized as a potential problem area and there may be a need, at some future date, to change current practices or to amend this rulemaking to cover this specific situation.

The change in section 3317 of the proposed rulemaking requiring rental payments in lieu of minimum royalties was intended to simplify accounting procedures for future leases. Many of those making comments stated that the wording of the proposed rulemaking was unclear as to when the new provisions would apply. Others pointed out that there would be some increased financial burden to lessees in the first year of production since royalties could not be credited against production royalties as could the minimum royalty required by existing leases. The accounting involved to negate this unintended result and make rentals creditable against royalties would be far more complicated and troublesome than existing procedures. The comments indicate that the proposed change in the procedure caused confusion and could create additional accounting burdens, contrary to the intent of the change. Therfore, the final rulemaking will contain the language of the existing regulations rather than the language of the proposed rulemaking.

One comment recommended that subpart 3317 be expanded to deal with net profit shares as well as rentals and royalties. New language will be added to the subpart after a new profit share bidding system has been developed and adopted.

A comment pointed out that the language of section 3318.1(f) was ambiguous and needed clarification. The section was changed to clarify that the filing of separate bonds, after default on the $300,000 area wide bond, would meet the bonding requirements for those leases on which the new separate bonds had been filed.

Comments on subpart 3318 addressed the amount of the bond and the rationale for requiring additional bonding. The general wording of the subpart has not been changed since it covers all situations, including particular site specific operating conditions where additional bonding might be warranted. Situations of this type can be best handled on a case-by-case basis at the discretion of the authorized officer rather than through requirements in regulations.

Subpart 3319, Assignments, Transfers and Extensions, received a number of comments, many of which were adopted. A major change in the subpart was the addition of a new section 3319.3, which spells out the 30-day time period allowed for Attorney General review of an assignment or transfer.

A number of comments made the point that operating agreements do not transfer title and should not be subject to the filing requirement in section 3319.2(a)(1). The wording of the section was changed to requie "filing of operating rights" which do affect record title and which, historically, have been required to be filed. Section 3319.2(a)(2) was changed to require that any document not required to be filed by this rulemaking must be accomapanied by a $25 fee per each lease affected and further to authorize the authorized officer to reject any such documents. This change will permit the recovery of costs related to the recording of unncessary documents and allow rejection of those documents that are not, in the opinion of the authorized officer, a proper part of the case file.

A number of comments noted that the proposed

change in section 3319.4(b), renumbered 3319.5 (b) in the final rulemaking, is a change from current practice and might discourage "farmouts". After careful review, it was determined that the change would not be a significant disincentive to "farmouts". The provision was left to stand as in the proposed rule. The change is consistent with Departmental efforts to encourage prompt and efficient development as required by section 5(a)(7) of the Act. While segregations, especially those near the end of the primary term, would be discouraged, a new subsection (c) was added to protect the small number of existing segregated leases.

It was suggested that the wording of 30 CFR 250.35 be incorporated in section 3319.5, renumbered section 3319.6 of the final rulemaking rather than referred to in the section. The reference to this section of title 30 of the Code of Federal Regulations is adequate for this rulemaking and the suggestion was not adopted. Another suggestion that the phrase "any officially designated subdivision" be defined was not adopted. This phrase has been in in the regulations on this subject for a number of years and has not caused confusion indicating that this term of art is well understood in the industry and does not need to be defined.

Several comments suggested that the word "accrued" be deleted from section 3320.1, as a modifier of the phrase "rentals and royalties" since rentals are payable in advance. While it is true that rentals and royalties are normally payable in advance and would not accrue, rentals not paid on time do accrue and are due before relinquishment takes effect. Therefore, the wording of the section was left essentially intact with only minor editorial changes to make the section clearer.

One comment asked that the phrase "at the option of the lessee" be inserted in that portion of section 3320.1 that requires the removal or conditioning of all platforms and other facilities upon relinquishment. This suggestion was not adopted. The section does not impose any unreasonable burden on the lessee and retains the flexibility needed by the Director, U. S. Geological Survey, to determine the best means of protecting the environment. Further, the language parallels that of 30 CFR 250.

A number of comments requested that section 3320.2(d) be amended to include all of the various conditions under which lease cancellation can occur. It is true that the language of the proposed rulemaking did not make reference to the five-year suspension period or incorporate all of the conditions for cancellation or fair value considerations, etc. The section was amended to delete all the procedural references and to include a cross-reference to 30 CFR 250 which deals at length with this subject.

One comment suggested that the language of the rulemaking be greatly expanded to detail the procedures and conditions under which the Bureau of Land Management would notify the U.S. Geological Survey and the Secretary of the Interior of the potential threats which might warrant cancellation. This suggestion was not adopted because these internal proedures, e.g., consultation among bureaus of the Department of the Interior, are covered by Secretarial Order 2974, and are not appropriate for inclusion in a rulemaking.

Many comments were made on the timing and use of the studies described in section 3331. Most of the recommendations were accommodated through the inclusion of the new policy section, 3300.0-2 and by changes in the wording of section 3331.

The new policy section included in this rulemaking states that the Secretary of the Interior shall use available environmental data in making decisions, i.e., for all decisions at all stages of the lengthy leasing and lease management process. The new policy section reemphasizes the commitment of the Department of the Interior and the Bureau of Land Management to use such data. This commitment is further strengthened by the addition of a recommended phrase to section 3331.1(e) that specifies that the studies program is designed to provide information in a form and "in a timeframe" that can be used in decisionmaking. These changes should remove any lingering doubt about the use of environmental data for decisionmaking.

The Outer Continental Shelf Lands Act Amendments specify a deadline of six months prior to a sale for the initiation of studies. The language of the rulemaking mirrors that requirement. It is emphasized that this does not preclude the use of data collected earlier in the decisionmaking process, nor does it preclude starting studies much earlier,including studies in areas not identified in the five-year leasing program, subject, of course, to budgetary and management constraints.

Specific starting times for studies (other than the six-month statutory requirement), were purposely not addressed in the rulemaking in order to allow the necessary flexibility to tailor the design of the studies program to make relevant data available in time to influence decisions. The time for initiation of studies was left flexible rather than set by this rulemaking to a specific term, as was recommended in several comments.

There were a number of comments that suggested the listing of the specific statutory requirements of section 20(a)(3) of the Outer Continental Shelf Lands Act, as amended, with regard to what subjects are to be studied, e.g., the introduction of drilling muds or the laying of pipe. These suggestions were adopted by the addition of a sentence to section 3331.1(a) dealing with the focus of the predictive studies to be carried out. However, the phrase

"environmental impacts of pollutants introduced into the environments" was used in place of the more restrictive language of the Amendments that does not provide an all-inclusive list of potential impacts. The broader language adopted for the final rulemaking allows, for example, the study of the effects of air pollution, as well as the impacts on marine biota of chronic or acute oil spills and drilling muds and fluids mentioned in the Act.

The phrase "if appropriate" was deleted from the last sentence of section 3331.1(d) as recommended in the comments. The purpose of the modifier was to indicate that the results of the studies would be used to improve mitigating measures only when the findings of the studies recommended such changes. The phrase was misleading and redundant and was dropped.

There was a recommendation to specify all the decision points in the leasing and resource management processes. This was not considered appropriate for inclusion in the rulemaking since many of the events and documents generated in the studies program are parts of internal processes which can vary over time according to a particular sale and the issues involved.

The addition of a separate sentence to section 3331.1(a) dealing specifically with predictive studies also points up the Department of the Interior's commitment to such studies and to the move away from the baseline studies approach. Several of the comments stated that the language of the proposed rulemaking did not place enough emphasis on the need for predictive studies.

Several recommended wording changes to section 3331 were not adopted because they added unneeded language that lengthened the rulemaking without adding any substance. There was, for example, a suggestion to reword the first sentence of section 3331.1(a) to read ". . .impacts on the human, marine and coastal environments of the outer continental shelf and coastal areas which may be affected by OCS oil and gas activities. . ." This change was not adopted as the environments listed in the suggestion and the text of the rulemaking include the OCS and the coastal areas by definition. Another suggestion on this section wanted studies sent to affected States. The availability of studies is fully covered by section 3300.2 and does not need to be provided for here. Finally, there was a suggestion to list the types of impacts and the types of resources to be studied. This suggestion was not adopted in that the general language of the section allows study of all impacts and all resources in all areas. The rulemaking already contains one listing of resource areas, section 3313.1(b), which is sufficient.

In subpart 3340, new section 3340.0-1, purpose, and section 3340.0-2, policy, have been added to expand on the purpose of the rulemaking, to draw attention to the compliance requirements of other affected Federal agencies, and to spell out the Department of the Interior's policy of engaging in advance transportation planning through programs designed to involve affected parties. These two new sections were added in response to a number of comments on these subjects.

One comment proposed an expanded definition section to clarify the classification of pipelines and the corresponding division of responsibilities between the Bureau of Land Management and the U. S. Geological Survey for granting rights-of-way, easements and permits on the Outer Continental Shelf Lands. Even though the suggestion was not adopted, it did focus on an issue of concern. The growth of the offshore pipeline network requires a careful look at jurisdictional questions and an evaluation of the effects on existing and future operations which could result from any change in definitions. The Depatment of the Interior is presently considering the pipeline jurisdiction questions.

One comment recommended a change in section 3340.1(a) providing that maximum environmental protection be achieved by utilization of the best available and safest technologies (BAST). While section 5(e) of the Outer Continental Shelf Lands Act, as amended, is phrased that way, the comment was not adopted. The intent of this section is to give the authorized officer sufficient discretion to assure maximum environmental protection as required by the Act under varying circumstances. Environmental stipulations may be required which are not related to technology. One comment pointed out that the word "Maximum" was not shown to modify environmental protection in the proposed rulemaking as it appears in section 5(e) of the Outer Contienntal Shelf Lands Act, as amended. The word has been restored to the section in the final rulemaking. However, the phrase "which the Secretary determines to be economically feasible" was not deleted as a test for BAST as was recommended by one comment, since section 21 of the Act, which deals with safety regulations, includes such a qualifier of the use of BAST. Because of this inclusion in the Act, the qualifier was retained in the final rulemaking wherever there is a reference to BAST.

Several comments requested a cross-reference to the U. S. Geological Survey regulations be added to section 3340.1(a)(1) which mentions BAST. This request was not accepted since the U. S. Geological Survey has not at this time completed its rulemaking on this subject.

One comment noted that section 3340.1(a)(1) should require the use of common pipelines wherever possible. This was not adopted as it was felt that the decision as to whether to require common pipelines should be made on a case-by-case basis after examining the facts rather

than having it mandated in every instance by regulation. The rulemaking allows the authorized officer to require the use of a common pipeline as part of the application approval process.

Several comments sought the deletion of the reference in section 3340.1(a)(4) to rights-of-way within boundaries of areas designated for pipelines. This suggestion has been adopted. The intergovernmental planning program provides an appropriate and flexible mechanism for designating transportation routes.

Several comments requested section 3340.1(a)(1) be changed to give preference to the rights of the initial or prior right-of-way grant over those of all subsequent grants. This was not adopted since the language of the section is consistent with the nature of the grant from the United States, i.e., it is a limited grant for a limited purpose. Safety and protection of the environment will be considerations that are essential ingredients of the authorized officer's decision. The authorized officer is given flexibility to quickly and equitably resolve conflicts between an applicant and the holders of existing grants by the removal of the protest provisions in section 3340.2-1(e)(1). The procedures provided by the rulemaking are adequate to protect the legitimate rights of prior holders.

A question was raised in the comments on the applicability of the new rental rates provided for in the proposed rulemaking. It is intended that the rental rates will apply to all rights-of-way, existing and new.

One comment noted that section 3340.1(a)(6) of the proposed rulemaking greatly expanded the provisions of the existing regulation dealing with the requirements for revocation or termination of a grant. The comment suggested cross-referencing Department of Transportation regulations on this subject rather than listing requirements as was done in the proposed rulemaking. This suggestion was not adopted because the Bureau of Land Management, as the permitting agency, needs to have its own authority to enforce practices it deems necessary for maximum environmental protection required under the law.

A comment suggested that the discretionary authority given the authorized officer be restricted to allow suspension only for and during an emergency which would result in serious, irreparable or immediate harm. This suggestion was not adopted. The rulemaking is in compliance with the broad language of the Outer Continental Shelf Lands Act, as amended, which allows suspension if there is a threat of harm. The language of section 3340.1(a)(7) was amended to include authority for suspension of operations in cases where there is a threat of serious harm.

A comment requesting section 3340.1(a)(7) be changed to allow Federal and State agency input to the determination of whether to suspend operations was adopted. However, a comment suggesting the addition of provisions for State involvement in all the procedures covered by section 3340.1 was not adopted because it would be redundant. State involvement and the consistency of the application with approved coastal zone management plans are already covered at length in sections 3340.2-2(c) and (d).

Another comment suggested that section 3340.1(a)(7) include a cross-reference to the U. S. Geological Survey suspension and cancellation provisions. This was not accepted because it would be inappropriate to cross-reference these provisions that deal with subjects other than pipelines. However, the section has been expanded considerably to address some of the conditions under which suspension and cancellation might occur and to provide public input into the determination to cancel or suspend operations.

The wording of action 3340.1(a)(8) was questioned in the comments. One change made was the deletion of the term "project" and the insertion of the term "pipeline" to make the section more precise. However, the section was not expanded to further define the phrase "unreasonable obstruction to fishing and shipping operations". The rulemaking will allow the determination of what constitutes an unreasonable obstruction on a case-by-case basis. It does not set a rigid definition of what constitutes an unreasonable obstruction that fits all situations.

There was a suggestion to require continuous monitoring of pipeline operations by the Bureau of Land Management as part of section 3340.1(a)(8). This provision was not considered necessary because the U. S. Coast Guard and the U. S. Geological Survey already monitor pipelines on a continuing basis. Should a leak be found, the various emergency provisions would come into effect. Should damage result from the leak, the Outer Continental Shelf Lands Act, as amended, provides several funds for clean-up and compensation. Since all of these provisions are covered by other regulations and other sections of this rulemaking, it was decided not to repeat the provisions in this section.

There was a suggestion to exempt common carriers from the requirements of section 3340.1(a)(9) to furnish the authorized officer with copies of contracts for transportation. This suggestion was not adopted since it is the intent of the section to obtain needed information only upon request.

There were several recommendations to amend section 3340.1(a)(10) to specifically exempt common carrier oil pipelines from the requirements to purchase crude oil. The language of the section parallels the language of the Outer Continental Shelf Lands Act, as amended, and has not been changed. The section is phrased

as an either/or provision and should not cause any operational problems. A primary intent of this section is to draw attention to the authority of the Federal Energy Regulatory Commission to regulate common carriers on the OCS.

A sentence was added to section 3340.1(c) that authorized temporary cessation of use for proper maintenance when a pipeline segment becomes corroded or otherwise worn and needs replacing. This provision is needed to cover this specific situation.

A recommendation was made that emphasis be given State involvement in the granting process by requiring that a copy of the application required by section 3340.2-1 be furnished an affected State. This recommendation was not adopted since sections 3340.2-2(c) and (d) and the policy of involving States through the intergovernmental planning program already give adequate opportunity for an affected State to be a part of the process. A related suggestion to make approval of an application dependent upon compliance with State law and regulations was not accepted. The provisions of sections 3340.2-2(c) and (d) describe and require involvement by an affected State in the approval of any grant that will subsequently cross or affect the coastal zone of a State.

The map scale notation in section 3340.2-1(b)(1) was inadequate in the proposed rulemaking and has been corrected in the final rulemaking to make it clear that the map scale is to be 1 inch to 4,000 feet.

A comment was received that recommended deletion of the requirement to specify the diameter of the pipeline in the application. This recommendation was not adopted because a considerable amount of detail is required to properly evaluate an application and clear it through the many approving agencies. Further, if the estimate of the diameter of the pipeline is incorrect or is revised an amended application can be filed.

One of the comments suggested that the application show the complete route of the proposed pipeline, through State as well as Federal lands. This suggestion was adopted and section 3340.2-1(b)(4) has been amended to reflect the change.

One of the comments suggested that the application map show geologic features which might affect construction and operation. This suggestion was not adopted since it is already a part of the detailed instructions for filing an application. In addition to the map accompanying the application described in section 3340.2-1(b), the applicant must submit other maps showing geologic hazards, locations of archeological resources, etc.

A comment noted that the wording of section 3340.2-1(e)(2) was ambiguous as to when and how "safety, environmental and economic factors" would be considered in approving or denying an application. The placing of this phrase is confusing and more properly belongs in the section 3340.2-2 which deals with approval action and, in fact, is already incorporated by reference in section 3340.2-2(a). The last sentence of this section which deals with the decision on the application was also moved to the approval section for clarity. In connection with moving language from section 3340.2-1 to section 3340.2-2, it was decided to rearrange section 3340.2-2 so that the approval action follows a natural sequence in the final rulemaking, making the whole process clearer.

One comment objected to the use of the word "may" in section 3340.2-2(a) as it applies to the actions, consultation efforts, etc., carried on by the authorized officer in considering an application. The wording has not changed since the conditions and issues involved vary greatly among applications and need to be handled on a case-by-case basis. The use of the word "shall" would require State and Federal consultation, public hearings, etc., for every application, even though analysis might indicate no environmental or other concerns sufficient to warrant such commitments of time and effort.

A recommendation was made that the Director prepare an environmental assessment before approving a grant for pipeline right-of-way. This recommendation was adopted but the balance of the recommendation which suggested referencing the National Environmental Policy Act and the Coastal Zone Management Act and spelling out the focus of such an assessment was not adopted. The phrase "in accordance with applicable policies and guidelines" is an adequate statement of the requirements governing the preparation of the environmental assessment and no further change is needed.

Reference to the intergovernmental planning program has been added to the newly numbered section 3340.2-2(a) as suggested in a number of comments. The addition of the reference serves to reemphasize the Department of the Interior's commitment to involve the affected States in policy and planning decisions. The addition also addresses the request of one State that it be involved in the annual review of rights-of-way grants. The intergovernmental planning program will provide an adequate vehicle for continuous input by the States.

One comment characterized the consistency provisions of section 3340.2-2(d) as "a weak attempt to circumvent the intent of the Coastal Zone Management Act." The consistency provisions refer to the intergovernmental planning program and require that the entire pipeline be described so it can be reviewed. An affected State will have early and ample opportunity to evaluate the right-of-way proposal in terms of consistency with its coastal zone plan. Further, the U. S. Geological Survey regulations deal with gathering lines normally described in development and production plans. A major

pipeline can proceed only through the granting of a right-of-way covered by an application filed with the Bureau of Land Management. A consistency determination is made only when a pipeline comes ashore or if a pipeline application is submitted as part of a development or production plan.

One comment suggested that the authorized officer be required to approve any application for a grant found to be in compliance with all pertinent law and regulations. The approval language of the rulemaking is consistent with the provisions of the Outer Continental Shelf Lands Act, as amended, in that it allows discretion for approving grants for pipeline rights-of-way. For this reason, the suggestion was not adopted.

The section covering construction procedure has been renumbered 3340.3 in the final rulemaking. One comment suggested that the word "significant" be added in section 3340.3(b) to modify the changes in conditions which may be grounds for altering the grant. The suggestion was adopted.

It was suggested in one of the comments that the requirements to "construct the pipeline within 5 years" be expanded to avoid the unlikely situation where a grant would be forfeited at the end of the fifth year if the pipeline was not quite finished. The wording has not been changed because this provision has never caused any operational problems and should not in the future.

A suggestion was received to limit abandonment requirements to those specified in section 3340.1(a)(6). Section 3340.5 has been revised to reference the earlier section.

Several comments objected to the provisions in section 3340.6 requiring prior approval of a change in the use or flow of a pipeline covered by a grant. The requirement has not been changed because the information is needed if the authorized officer is to be able to carry out responsibilities under the law and regulations.

One comment questioned the authority of the Secretary of the Interior to require bonding for pipeline right-of-way grants. While there is no express authority in the Outer Continental Shelf Lands Act, as amended, requiring bonding, the general grant of authority in section 5(e) of the Act allowing the Secretary to issue appropriate regulations is the basis for the bonding requirement. Without the protection afforded by bonding, it is questionable that the Secretary of the Interior could adequately carry out his responsibilities to manage the resources and protect the environments of the Outer Continental Shelf. Several comments questioned whether it was the intent of the rulemaking to require separate bonds for a lease and a pipeline right-of-way grant. That is the intent of the rulemaking. The rulemaking also requires the posting of a bond for existing rights-of-way not presently bonded.

The provisions for reimbursement of costs contained in section 3340.8 have been deleted from the final rulemaking. This very complicated issue needs further study before a final decision is made on how cost recovery will be applied to the outer continental shelf. If it is decided that cost recovery should be applied, the regulations of this part will be amended.

Editorial changes and corrections have been made throughout the rulemaking as necessary.

The principal authors of this final rulemaking are William J. Quinn, Division of Minerals Program Development and Analysis, Hans L. Larsen and Chris Oynes, Division of Mineral Resources, Robert C. Bruce, Office of Legislation and Regulatory Management, all of the Bureau of Land Management, and Sandra E. Seim, staff assistant to the Assistant Secretary for Land and Water Resources.

It is hereby determined that the publication of this document is not a major Federal action significantly affecting the quality of the human environment and that no detailed statement pursuant to section 102.2(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332 (2)(C)) is required.

The Department of the Interior has determined that this document is not a significant regulatory action requiring the preparation of a regulatory analysis under Executive Order 12044 and 43 CFR Part 14.

Under the authority of the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 et. seq.), Part 3300, Group 3300, Subchapter C, and Part 2880, Subchapter B, Chapter II, Title 43 of the Code of Federal Regulations are amended as set forth below.

GUY R. MARTIN,
Assistant Secretary of the Interior

JUNE 25, 1979

2. Regulations, 43 CFR 3300, Outer Continental Shelf Minerals and Rights-of-Way Management Title 43 CFR, revised as of October 1, 1979, amended by: 45 FR 69174-75, October 17, 1980.

Subpart 3300—Outer Continental Shelf Minerals and Rights-of-Way Management, General

3340.7 Bonding.

Appendix A--Suggested Bid Form.
Appendix B--Required Joint Bidder's Statement.

AUTHORITY: 43 U.S.C. 1331 et seq.

SOURCE: 44 FR 38276, June 29, 1979, unless otherwise noted.

Subpart 3300--Outer Continental Shelf Mineral and Rights-of-way Management, General

§ 3300.0-1 Purpose.

The purpose of these regulations is to establish the procedures under which the Secretary of the Interior will exercise the authority granted to administer a leasing program for minerals and grant rights-of-way on the submerged lands of the Outer Continental Shelf.

§ 3300.0-2 Policy.

The management of Outer Continental Shelf resources is to be conducted in accordance with the findings, purposes and policy directions provided by the Outer Continental Shelf Lands Act Amendments of 1978 (43 U.S.C. 1332, 1801, 1802), and other Executive, legislative judicial and Departmental guidance. The Secretary of the Interior shall consider available environmental information in making decisions affecting Outer Continental Shelf resources.

§ 3300.0-3 Authority.

The Outer Continental Shelf Lands Act as amended, (43 U.S.C. § 1331 et seq.) authorizes the Secreary of the Interior to issue, on a competitive basis, leases for oil and gas, sulphur, geopressured-geothermal and associated resources, and other minerals in submerged lands of the Outer Continental Shelf. The Act authorizes the Secretary of the Interior to grant rights-of-way through the submerged lands of the Outer Continental Shelf. The Energy Policy and Conservation Act of 1975 (42 U.S.C. 6213), prohibits joint bidding by major oil and gas producers.

§ 3300.0-5 Definitions.

As used in this part, the term:

(a) "Act" refers to the Outer Continental Shelf Lands Act of August 7, 1953 (43 U.S.C. 1331 et seq.) as amended.

(b) "Director" means the Director, Bureau of Land Management.

(c) "OCS" means the Outer Continental Shelf, as that term is defined in 43 U.S.C. 1331(a).

(d) "Secretary" means the Secretary of the Interior.

(e) "Bureau" means the Bureau of Land Management.

(f) "Coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal States, and includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches, which zone extends seaward to the outer limit of the United States territorial sea and extends inland from the shore lines to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States pursuant to the authority of section 305(b)(1) of the Coastal Zone Management Act of 1972 (16 U.S.C. 1454(b)(1));

(g) "Affected State" means, with respect to any program, plan, lease sale, or other activity, proposed, conducted, or approved pursuant to the provisions of the Act, any State--

(1) The laws of which are declared, pursuant to section 4(a)(2) of the Act, to be the law of the United States for the portion of the Outer Continental Shelf on which such activity is, or is proposed to be conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or structure referred to in section 4(a)(1) of the Act;

(3) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment which was extracted from the Outer Continental Shelf and transported directly to such State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Secretary as a State in which there is a substantial probability or significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the Outer Continental Shelf; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oilspill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities;

(h) "Marine environment" means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, conditions, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone,

transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the Outer Continental Shelf;

(i) "Coastal environment" means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, conditions, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone;

(j) "Human environment" means the physical, social, and economic components, conditions, and factors which interactively determine the state, condition, and quality of living conditions, employment, and health of those affected, directly or indirectly, by activities occurring on the Outer Continental Shelf;

(k) "Mineral" includes oil, gas, sulphur, geopressured-geothermal and associated resources, and such other minerals as are disposable under mineral laws applicable to the public lands.

(l) "Authorized officer" means any person authorized by law or by delegation of authority to or within the Bureau of Land Management to perform the duties described in this part.

§ 3300.0-6 Cross references.

(a) For Geological Survey regulations governing exploration, development and production on leases, see 30 CFR 250 et seq.

(b) For multiple use conflicts see the Environmental Protection Agency listing of ocean dumping sites--40 CFR 228.

(c) For related National Oceanic and Atmospheric Administration programs see:

(1) Marine sanctuary regulations, 15 CFR 922;

(2) Fishermen's Contingency Fund, 50 CFR 296;

(3) Coastal Energy Impact Program, 15 CFR 931;

(d) For Federal Maritime Commission regulations on the oil spill liability of vessels, see 46 CFR 544.

(e) For Coast Guard regulations on oil spill liability of operators, see 33 CFR 135-6.

(f) For Coast Guard regulations on port access routes, see 33 CFR 164.

(g) For compliance with the National Environmental Policy Act, see 40 CFR 1500-08.

(h) For Department of Transportation regulations on offshore pipeline facilities, see 49 CFR 195.

(i) For Department of Defense regulations on military activities on offshore areas, see 32 CFR 252.

§ 3300.1 Leasing maps and diagrams.

(a) Any area of the OCS which has been appropriately platted as provided in paragraph (b) of this section, is subject to lease for any mineral not included in a subsisting lease issued under the Act or meeting the requirements of subsection (a) of section 6 of the Act. Before any lease is offered or issued an area may be (1) withdrawn from disposition pursuant to section 12(a) of the Act, or (2) designated as an area or part of an area restricted from operation under section 12(d) of the Act.

(b) The Bureau shall prepare leasing maps and official protraction diagrams of areas of the OCS. The areas included in each mineral lease shall be in accordance with the appropriate leasing map or official protraction diagram.

§ 3300.2 Information to States.

(a) The information covered in the subsection is prepared by or directly obtained by the Director. Such information is typically not considered to be proprietary or privileged, with the primary exception of specific tract nominations by industry received in response to a Call for Nominations and Comments issued by the Secretary. All other proprietary and privileged information is obtained by or under the control of the U. S. Geological Survey which is responsible for its release in accordance with its regulations (see 30 CFR 250, 251, 252).

(b) The Director, in conjunction with the Director, U. S. Geological Survey, shall prepare an index to OCS Information (see 30 CFR 252.5). The index shall list all relevant actual or proposed programs, plans, reports, environmental impact statements, nominations information, environmental study reports, lease sale information and any similar type of relevant information including modifications, comments and revisions, prepared by or directly obtained by the Director under the Act. The index shall be sent on a regular basis to affected States and, upon request, it shall be sent to any affected local government. The public shall be informed of the availability of the index.

(c) Upon request, the Director shall transmit to affected States, local governments or the public, a copy of any information listed in the index which is subject to the control of the Bureau in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and regulations implementing said Act, and the regulations contained in 43 CFR Part 2, except as provided in paragraph (d) of this section.

(d) Upon request, the Director shall provide relative indications of interest on tracts nominated as well as any comments filed in response to a Call for Nominations and Comments for a proposed sale. However, no information transmitted shall identify any particular tract with the name of any particular party so as not to compromise the competitive position of any participants in the nominating process.

§ 3300.3 Helium.

(a) Each lease issued or continued under

these regulations shall be subject to a reservation by the United States, under section 12(f) of the Act, of the ownership of and the right to extract helium from all gas produced from the leased area.

(b) In case the United States elects to take the helium, the lessee shall deliver all gas containing helium, or the portion of gas desired, to the United States at any point on the leased area or at an onshore processing facility. Delivery shall be made in the manner required by the United States to such plants or reduction works as the United States may provide.

(c) The extraction of helium shall not cause a reduction in the value of the lessee's gas or any other loss for which he is not reasonably compensated, except for the value of the helium extracted. The United States shall determine the amount of reasonable compensation. The United States shall have the right to erect, maintain and operate on the leased area any and all reduction works and other equipment necessary for the extraction of helium. The extraction of helium shall not cause substantial delays in the delivery of natural gas produced to the purchaser of that gas.

§ 3300.4 Payment.

(a) Payments of bonuses, including deferred bonuses, first year's rental, other payments due upon lease issuance, filing charges and fees, annual rentals and costs for grants of pipeline rights-of-way shall be made to the manager of the appropriate OCS field office. All payments shall be made by cash, check or bank draft payable to the Bureau of Land Management, unless otherwise directed by the Secretary.

(b) All other payments required by a lease or the regulations in this part shall be payable to the United States Geological Survey.

Subpart 3310—Leasing Program

§ 3310.0-5 Definitions.

As used in this subpart, the term--"Affected State" and "affected States" means Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Louisiana, Texas, California, Oregon Washington, and Alaska.

§ 3310.1 Receipt and consideration of nominations; public notice and participation.

(a) During preparation of a proposed 5-year leasing program, the Secretary shall invite and consider suggestions and relevant information for such program from Governors of affected States, local government, industry, other Federal agencies, including the Attorney General in consultation with the Federal Trade Commission, and all interested parties, including the general public. This request for information shall be issued as a notice in the Federal Register. Local governments wishing to respond to such request shall first submit their responses to the Governor of the State in which the local government is located.

(b) The Secretary shall send letters to the Governors of the affected States requesting them to identify specific laws, goals, and policies which they believe should be considered by the Secretary in connection with the leasing program. The Secretary shall also request from the Secretary of Energy information on regional and national energy markets, on OCS production goals and on transportation networks.

§ 3310.2 Review by State and local governments.

(a)(1) The Secretary shall prepare a proposed leasing program. At least 60 days prior to publication of the proposed program in the Federal Register, a copy of the draft of the proposed program shall be forwarded to the Governor of each affected State for comment. The Governor may solicit comments from local governments in his or her State which the Governor determines will be affected by the proposed program.

(2) The Secretary shall reply in writing to any comment on the draft of the proposed program from the Governor of an affected State which is received at least 15 days prior to the submission of the proposed program to the Congress and publication in the Federal Register. All such correspondence between the Secretary and Governor of such State shall accompany the proposed program when it is submitted to the Congress.

(b) The proposed leasing program shall be submitted to the Governors of the affected States for review and comment at the time it is submitted to the Congress and the Attorney General and published in the Federal Register. The Governor of an affected State shall, upon request from any local government affected by the program, submit a copy of the proposed program to such local government. Comments and recommendations on any aspect of the proposed program may be submitted by a State or local government to the Secretary within 90 days after the date of its publication in the Federal Register. Comments and recommendations from local governments shall be submitted first to the Governor of the State in which the local government is located.

(c) At least 60 days prior to approving the final leasing program and any later significant

revision, the Secretary shall submit it to the President and the Congress, together with any comments. The Secretary shall indicate in such submission why any specific recommendation of the Attorney General or of a State or local government was not accepted.

§ 3310.3 Periodic consultation with interested parties.

The Secretary shall provide for periodic consultation with State and local governments, existing and potential oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in any activity in or on the OCS, including those involved in fish and shellfish recovery, and recreational activities. This consultation shall take place primarily through appropriate public notice as described in §§ 3310.1 and 3310.2 and through the OCS Advisory Board and its committees, on a regional and national basis. Meetings of the OCS Advisory Board shall be held on specific issues required by the Board's charter.

§ 3310.4 Consideration of coastal zone management program.

In the development of the leasing program, consideration shall be given to the coastal zone management program being developed or administered by an affected coastal State under section 305 or 306 of the Coastal Zone Management Act of 1972 as amended (16 U.S.C. 1454, 1455). Information concerning the relationship between a State's coastal zone management program and OCS oil and gas activity shall be requested from the Governors of the affected coastal States and from the Secretary of Commerce prior to the development of the proposed leasing program at the time information is requested under § 3310.1 of this title.

Subpart 3312—Reports From Federal Agencies

§ 3312.1 General.

For oil and gas lease sales shown in an approved leasing schedule and as the need arises for other mineral leasing, the Director shall request the Director, Geological Survey, to prepare a report describing the general geology and potential mineral resources of the area under consideration. The Director shall request other interested Federal agencies to prepare reports describing, to the extent known, any other valuable resources contained within the general area and the potential effect of mineral operations upon the resources or upon the total environment or other uses of the area.

Subpart 3313—Call for Nominations and Comments

§ 3313.1 Nomination of tracts.

(a) The Director may receive and consider tract nominations or requests describing areas and expressing an interest in leasing of minerals.

(b) In accordance with an approved program and schedule for the leasing of lands which may contain oil and gas, the Director shall issue Calls for Nominations and Comments on tracts for the leasing of such minerals in specified areas. The Call for Nominations and Comments shall be published in the Federal Register and may be published in other publications as desirable. Nominations and comments on tracts shall be addressed to the manager of the appropriate OCS office, with copies to the Director and to the Director and the Regional Conservation manager of the Geological Survey. The Director shall also request comments on tracts which should receive special concern and analysis. For an oil and gas lease sale call area, the Director may request comments concerning geological conditions, including bottom hazards; archaeological or cultural sites on the seabed or nearshore; multiple uses of the proposed leasing area, including navigation, recreation and fisheries; and other socioeconomic, biological and environmental information.

§ 3313.2 Tracts near Coastal States.

(a) At the time nominations are solicited for leasing of tracts within 3 geographical miles of the seaward boundary of any coastal State, the Secretary shall provide the Governor of that State information required under section 8(g)(1) of the act. The Director shall furnish information identifying the areas for leasing as well as all relevant available environmental data for such areas (see 30 CFR 251.14).

(b) After receipt of nominations for tracts within the area described in (a) hereof, the Secretary shall inform the Governor of those tracts that are to be given further consideration for leasing. The Secretary shall enter into consultation with the Governor to determine whether the area may contain oil or gas pools or fields underlying both the OCS and lands subject to the jurisdiction of the State.

(c) After selection for leasing of those tracts which may have oil or gas pools or fields underlying both the OCS and lands under State jurisdiction, the Secretary shall offer the Governor an opportunity to enter into an agreement for the equitable disposition of revenues from such tracts under section 8(g)(2) of the Act.

(d) If no agreement can be reached within 90 days of the Secretary's offer, the tracts may be leased and all revenues deposited in a separate Treasury account pending equitable dis-

position of the revenues under section 8(g)(3) and (4) of the Act.

Subpart 3314—Tentative Tract Selection

§ 3314.1 General.

(a) The Director, in consultation with the Director, Geological Survey and other appropriate Federal agencies, shall recommend to the Secretary tracts for further environmental analysis and consideration for leasing. The Director, on his or her own motion, in consultation with the Director, Geological Survey, may include in the recommendation tracts which have not been nominated. In making a recommendation, the Director shall consider all available environmental information, multiple-use conflicts, resource potential, industry interest and other relevant information. Comments received from States and local governments and interested parties in response to Calls for Nominations and Comments shall be considered in making recommendations.

(b) After tracts have been tentatively selected, the Director shall evaluate fully the potential effect of leasing on the human, marine and coastal environments, and develop measures to mitigate adverse impacts, including lease stipulations. The views and recommendations of Federal agencies, State agencies, local governments, organizations, industries, and the general public shall be utilized, as appropriate. The Director may hold public hearings on the environmental analysis after appropriate notice.

(c) In general, the Director shall seek to inform the public as soon as possible of tract additions or deletions that occur after the tentative selection of tracts.

§ 3314.2 Tract size.

A tract selected for leasing shall consist of a compact area not exceeding 5760 acres, unless the authorized officer finds that a larger area is necessary to comprise a reasonable economic production unit.

Subpart 3315—Lease Sales

§ 3315.1 Proposed Notice of Sale.

(a) The Director shall in consultation with appropriate Federal agencies develop measures, including lease stipulations and conditions, to mitigate adverse impacts on the environments. For oil and gas lease sales, appropriate proposed stipulations and conditions shall be contained in the proposed notice of lease sale.

(b) A proposed notice of lease sale shall be submitted to the Secretary for approval. All comments and recommendations received and the Director's findings or actions thereon, shall also be forwarded to the Secretary.

(c) Upon approval by the Secretary, the proposed Notice of Sale shall be sent to the Governor of any affected State and be published in the Federal Register.

§ 3315.2 State comments.

(a) Within 60 days after notice of a proposed lease sale, a Governor of any affected State or any affected local government in such State may submit recommendations to the Secretary regarding the size, timing or location of the proposed lease sale. Prior to submitting recommendations to the Secretary, any affected local government shall forward such recommendation to the Governor.

(b) The Secretary shall accept such recommendations of the Governor and may accept recommendations of any affected local government if he determines, after having provided the opportunity for consultation, that they provide for a reasonable balance between the national interest and the well-being of the citizens of the affected State. A determination of the national interest shall be based on the findings, purposes and policies of the Act.

(c) The Secretary shall communicate to the Governor, in writing, the reasons for his determination to accept or reject such Governor's recommendations, or to implement any alternative means identified in consultation with the Governor to provide for a reasonable balance between the national interest and the well-being of the citizens of the affected State.

§ 3315.3 Department of Energy review.

The Secretary shall allow 30 days for review of the lease terms and conditions by the Secretary of Energy, unless there is an agreement that a shorter period provides a reasonable opportunity for review.

§ 3315.4 Notice of sale.

(a) Upon approval of the Secretary, the Director shall publish the notice of lease sale in the Federal Register as the official publication, and may publish the notice in other publications. The publication in the Federal Register shall be at least 30 days prior to the date of the sale. The notice shall state the place and time at which bids shall be filed, and the place, date and hour at which bids shall be opened. The notice shall contain a description of the areas to be offered for lease and any stipulations, terms and conditions of the sale.

(b) Tracts shall be offered for lease by competitive sealed bidding under conditions specified in the notice of lease sale and in accordance with all applicable laws and regulations. Suggested formats for bidder submissions and

joint bidder's statements appear in Appendix A and B of this part.

(c) The notice of lease sale shall contain a reference to the OCS lease form which shall be issued to successful bidders.

(d) With the approval of the Secretary, the Director may defer any part of the payment of the cash bonus according to a schedule announced at the time of the notice of lease sale. Payment shall be made no later than 5 years after the date of the lease sale. The schedule shall contain provisions for guaranteed payment of a deferred bonus.

(e) In order to obtain statistical information to determine which bidding alternatives best accomplish the purposes and policies of the act, the Director may, until September 18, 1983, require each bidder to submit bids for any OCS area in accordance with more than one of the bidding systems described in section 8(a)(1) of the Act. No more than 10 percent of the tracts offered each year shall contain such a requirement. Leases may be awarded using a bidding alternative selected at random for statistical purposes, if it is otherwise consistent with the purposes and policies of the Act.

Subpart 3316--Issuance of Leases

§ 3316.1 Qualifications of lessees.

(a) In accordance with section 8 of the Act, leases shall be awarded only to the highest responsible qualified bidder.

(b) Mineral leases issued pursuant to section 8 of the Act may be held only by: (1) citizens and nationals of the United States, (2) aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101 (a)(20); (3) private, public or municipal corporations organized under the laws of the United States or of any State or of the District of Columbia or territory thereof, or (4) association of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States.

§ 3316.2 Lease term.

(a) All oil and gas leases shall be issued for an initial period of 5 years, or not to exceed 10 years where the authorized officer finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions.

(b) An oil and gas lease shall continue after such initial period for as long as oil or gas is produced from the lease in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted. The term of an oil and gas lease is subject to further extension as provided in § 3319.9 of this title.

(c) Sulphur leases shall be issued for a term not to exceed 10 years and so long thereafter as sulphur is produced from the leasehold in paying quantities, or drilling, well reworking, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are conducted thereon.

(d) Other minerals leases shall be issued for such term as may be prescribed at the time of offering the leases in the notice of lease sale.

§ 3316.3 Joint Bidding Provisions.

§ 3316.3-1 Definitions.

The following definitions shall be applicable to § 3316.3 of this title:

(a) "Single bid" means a bid submitted by one person for an oil and gas lease under section 8(a) of the Act.

(b) "Joint bid" means a bid submitted by two or more persons for an oil and gas lease under section 8(a) of the Act.

(c) "Average Daily Production" is the total of all production in an applicable production period which is chargeable under § 3316.3-3 of this title divided by the exact number of calendar days in the applicable production period.

(d) "Barrel" means 42 United States gallons.

(e) "Crude Oil" means a mixture of liquid hydrocarbons including condensate that exists in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities, but does not include liquid hydrocarbons produced from tar sand, gilsonite, oil shale, or coal.

(f) "An Economic Interest" means any right to, or any right dependent upon, production of crude oil, natural gas, or liquefied petroleum products and shall include, but not be limited to, a royalty interest, or overriding royalty interest, whether payable in cash or in kind, a working interest, a net profit interest, a production payment, or a carried interest.

(g) "Liquefied Petroleum Products" means natural gas liquid products including the following: ethane, propane, butane, pentane, natural gasoline, and other natural gas products recovered by a process of absorption, adsorption, compression, or refrigeration cycling, or a combination of such processes.

(h) "Natural Gas" means a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist in the gaseous phase.

(i) "Oil and Gas Lease" means an oil and gas lease either offered or issued pursuant to the provisions of the Act.

(j) "Owned" means:

(1) With respect to crude oil--having either an economic interest in or a power of disposition over the production of crude oil:

(2) With respect to natural gas--having

either an economic interest in or a power of disposition over the production of natural gas; and

(3) With respect to liquefied petroleum products—having either an economic interest in or a power of disposition over any liquefied petroleum product at the time of completion of the liquefaction process.

(k) "Prior Production Period" means the continuous six month period of January 1 through June 30 preceding November 1 through April 30 for joint bids submitted during the six month bidding period from November 1 through April 30, and means the continuous six month period of July 1 through December 31 preceding May 1 through October 31 for joint bids submitted during the six month bidding period from May 1 through October 31.

(l) "Production"--(1) of crude oil means the volume of crude oil produced worldwide from reservoirs during the prior production period. The amount of such crude oil production shall be established by measurement of volumes delivered at the point of custody transfer (e.g., from storage tanks to pipelines, trucks, tankers, or other media for transport to refineries or terminals) with adjustments for:

(i) Net differences between opening and closing inventories, and

(ii) Basic sediment and water;

(2) Of natural gas means the volume of natural gas produced worldwide from natural oil and gas reservoirs during the prior production period, with adjustments, where applicable, to reflect

(i) The volume of gas returned to natural reservoirs; and

(ii) The reduction of volume resulting from the removal of natural gas liquids and nonhydrocarbon gases.

(3) Of liquefied petroleum products means the volume of natural gas liquids produced from reservoir gas and liquefied at surface separators, field facilities, or gas processing plants worldwide during the prior production period; these liquefied petroleum products include the following:

(i) Condensate—natural gas liquids recovered from gas well gas (associated and nonassociated) in separators or field facilities;

(ii) Gas Plant Products—natural gas liquids recovered from natural gas in gas processing plants and from field facilities. Gas plant products shall include the following as classified according to the standards of Natural Gas Processors Association (NGPA) or the American Society for Testing and Materials (ASTM):

(A) Ethane--C^2H^6

(B) Propane--C^3H^8

(C) Butane--C^4H^{10} including all products covered by NGPA specifications for commercial butane.

(1) Isobutane.

(2) Normal butane.

(3) Other butanes--all butanes not included as isobutane or normal butane;

(D) Butane-Propane Mixtures--All products covered by NGPA specifications for butane-mixtures;

(E) Natural Gasoline--A mixture of hydrocarbons extracted from natural gas, which meet vapor pressure, end point, and other specifications for natural gasoline set by NGPA;

(F) Plant Condensate--A natural gas plant product recovered and separated as a liquid at gas inlet separators or scrubbers in processing plants or field facilities; and

(g) Other Natural Gas Plant Products meeting refined product standards (i.e., gasoline, kerosene, distillate, etc.).

(m) "Six Month Bidding Period" means the six month period of time

(1) From May 1 through October 31; or

(2) From November 1 through April 30, respectively.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

§ 3316.3-2 Joint bidding requirements.

(a) Any person who submits a joint bid for any oil and gas lease during a 6-month bidding period, and who was chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products, shall have filed under oath with the Director, a Statement of Production of crude oil, natural gas and liquified petroleum products, hereinafter referred to as a Statement of Production, no later than 45 days prior to the commencement of the applicable 6-month bidding period of May 1 through October 31, and November 1 through April 30. Statements of Production shall be submitted to the Director, Bureau of Land Management (Attention: 541), Washington, D.C. 20240. The Statement of Production shall indicate that the person was chargeable, in accordance with § 3316.3-3 of this title, with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products for the prior production period. The Director shall publish semi-annually in the Federal Register a "List of Restricted Joint Bidders" to be effective immediately upon publication and to continue in force and effect until a subsequent list is published. The "List of Restricted Joint Bidders" shall consist of those persons, who in the judgment of the Director, based on information available to him, including, but not limited to, sworn Statements of Production, are chargeable under § 3316.3-3 of this title with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products for the prior production period.

(b) When a person is placed on the List of Restricted Joint Bidders the Director shall serve that person either personally or by certified mail, return receipt requested, with a copy of the Director's Order placing that person on the List of Restricted Joint Bidders. Any appeal from that Order or from an adverse effect of that Order shall be made in accordance with the provisions of 43 CFR Part 4.

(c) The submission of a Statement of Production or of a detailed Report of Production under § 3316.4(h) of this title which misrepresents the chargeable production of the reporting person shall constitute failure to comply with these regulations and any lease awarded in reliance on that Statement or Report of Production may be canceled, pursuant to section 8(o) of the act and regulations issued thereunder as having been obtained by fraud or misrepresentation.

(d) The Secretary may exempt a person from the provisions of §§ 3316.3-2(a), 3316.3-4, 3316.3-4(h) and 3319.1(b) of this title if it is found, on the record, after an opportunity for an agency hearing, that lands being offered have extremely high cost exploration and development problems and that exploration and development will not occur on such lands unless the exemption is granted.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979; 45 FR 69174, Oct. 17, 1980]

§ 3316.3-3 Chargeability for production.

(a) As used in this section the following definitions shall control:

(1) "Person" means a natural person or company.

(2) "Company" means a corporation, a partnership, an association, a joint-stock company, a trust, a fund, or any group of persons whether incorporated or not; it also means any receiver, trustee in bankruptcy, or similar official acting for such a company.

(3) "Subsidiary" means a company 50 percent or more of whose stock or other interest having power to vote for the election of directors, trustees, or other similar controlling body of the company is directly or indirectly owned, controlled, or held with the power to vote by another company; a subsidiary shall be deemed a subsidiary of the other company owning, controlling, or holding 50 percent or more of the stock or other voting interest.

(4) "Security or securities" means any note, stock, treasury stock, bond, debenture, evidence of indebtedness, certificate of interest or participation in any profit-sharing agreement, collateral-trust certificate, pre-organization certificate or subscription, transferable share, investment contract, voting-trust certificate, certificate of deposit for a security, fractional undivided interest in oil, gas, or other mineral rights, or, in general, any interest or instrument commonly known as a "security" or any certificate of interest or participation in, temporary or interim certificate for, receipt for, guarantee of, or warrant or right to subscribe to or purchase any of the foregoing.

(b) A person filing a Statement of Production under § 3316.3-2 of this title shall be charged with the following production during the applicable production period:

(1) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products which it owned worldwide;

(2) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every subsidiary of the reporting person;

(3) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any person or persons of which the reporting person is a subsidiary; and

(4) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any subsidiary, other than the reporting person, of any person or persons of which the reporting person is a subsidiary.

(c) A person filing a Statement of Production shall be charged with, in addition to the production chargeable under paragraph (b) of this section, but not in duplication thereof, its proportionate share of the average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every person: (1) Which has an interest in the reporting person, and (2) in which the reporting person has an interest, whether the interest referred to in paragraphs (c)(1) and (2) of this section is by virtue of ownership of securities or other evidence of ownership, or by participation in any contract, agreement, or understanding respecting the control of any person or of any person's production of crude oil, natural gas, or liquefied petroleum products, equal to said interest. As used in paragraph (c) of this section "interest" means an interest of at least 5 percent of the ownership or control of a person.

(d) All measurements of crude oil and liquefied petroleum products under this section shall be at 60° F.

(e)(1) For purposes of computing production of natural gas under § 3316.3-2 of this title, chargeability under this section, and reporting under § 3316.4(h) of this title, 5,626 cubic feet of natural gas at 14.73 pounds per square inch (msl) shall equal one barrel.

(2) For purposes of computing production of liquefied petroleum products under § 3316.3-2 of this title, chargeability under § 3316.4 (h) of this title, 1.454 barrels of natural gas liquids at 60° F. shall equal one barrel

of oil.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

§ 3316.3-4 Bids disqualified.

The following bids for any oil and gas lease shall be disqualified and rejected in their entirety:

(a) A joint bid submitted by 2 or more persons who are on the effective List of Restricted Joint Bidders; or

(b) A joint bid submitted by two or more persons when 1 or more of those persons is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products and has not filed a Statement of Production as required by § 3316.3-2 of this title for the applicable 6-month bidding period, or (2) any of those persons have failed or refused to file a detailed report of production when required to do so under § 3316.4(h) of this title, or

(c) A single or joint bid submitted pursuant to an agreement (whether written or oral, formal or informal, entered into or arranged prior to or simultaneously with the submission of such single or joint bid, or prior to or simultaneously with the award of the bid upon the tract) which provides (1) for the assignment, transfer, sale, or other conveyance of less than a 100 percent interest in the entire tract on which the bid is submitted, by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or (2) for the assignment, sale, transfer or other conveyance of less than a 100 percent interest in any fractional interest in the entire tract (which fractional interest was originally acquired by the person making the assignment, sale, transfer or other conveyance, under the provisions of the Act) by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or (3) for the assignment, sale, transfer, or other conveyance of any interest in a tract by a person or persons not on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to 2 or more persons on the same List of Restricted Joint Bidders; or (4) For any of the types of conveyances described in paragraphs (c)(1), (2), or (3) of this section where any party to the conveyance is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products and has not filed a Statement of Production pursuant to § 3316.3-2 of this title for the applicable 6-month bidding period. Assignments expressly required by law, regulation, lease or stipulation to lease shall not disqualify an otherwise qualified bid; or

(d) A bid submitted by or in conjunction with a person who has filed a false, fraudulent or otherwise intentionally false or misleading detailed Report of Production.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979; 45 FR 69175, Oct. 17, 1980]

§ 3316.4 Submission of bids.

(a) A separate sealed bid shall be submitted for each tract unit bid upon as described in the notice of lease sale. A bid may not be submitted for less than an entire tract.

(b) Each bidder shall submit with the bid, a certified or cashier's check or bank draft on a solvent bank, or cash, or any other form of payment approved by the Secretary for one-fifth of the amount of the cash bonus, unless otherwise stated in the Notice of Sale.

(c) If the bidder is an individual a statement of citizenship shall accompany the bid.

(d) If the bidder is an association (including a partnership), the bid shall also be accompanied by a certified copy of the articles of association or appropriate reference to the record of the Bureau in which such a copy has already been filed, with a statement as to any subsequent amendments.

(e) If the bidder is a corporation, the following information shall be submitted with the bid;

(1) A certified copy of the articles of incorporation and a copy either of the minutes of the meeting of the board of directors or of the bylaws indicating that the person signing the bid has authority to do so, or,

(2) In lieu of such a copy, a certificate to that effect signed by the secretary or the assistant secretary of the corporation over the corporate seal, or appropriate reference to the records submitted to the Bureau in connection with which such articles and authority have been previously furnished,

(3) The bid shall be executed in conformance with corporate requirements.

(f) Bidders should be aware of the provisions of 18 U.S.C. 1860, prohibiting unlawful combination or intimidation of bidders.

(g) Every joint bid submitted for any oil and gas lease shall be accompanied by a sworn statement by each joint bidder stating that the bid is not disqualified under § 3316.3-4(c) of this title.

(h) To verify the accuracy of any statement submitted pursuant to § 3316.3-2 of this title and paragraph (g) of this section, the Director may require the person submitting such information to: (1) submit no later than 30 days after

receipt of the request by the Director, a detailed Report of Production which shall list, in barrels, the average daily production of crude oil, natural gas and liquefied petroleum products chargeable to the reporting person in accordance with § 3316.3-3 of this title for the prior production period, and (2) permit the inspection and copying by an official of the Department of the Interior of such documents, records of production of crude oil, natural gas and liquefied petroleum products, analyses and other material as are necessary to demonstrate the accuracy of any statement or information contained in any Report of Production.

(i) No bid for a lease may be submitted if the Secretary finds, after notice and hearing, that the bidder is not meeting due diligence requirements on other OCS leases.

[45 FR 69175, Oct. 17, 1980]

§ 3316.5 Award of leases.

(a) Sealed bids received in response to the notice of lease sale shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids shall be accepted or rejected at that time.

(b) The United States reserves the right to reject any and all bids received for any tract, regardless of the amount offered.

(c) In the event the highest bids are tie bids, the tie bidder (unless they would be disqualified under § 3316.1(b) of this title, or disqualified under § 3316.3-4 of this title if their bids had been joint bids) may file with the Director, within 15 days after notification, an agreement to accept the lease jointly; otherwise all bids shall be rejected.

(d) Pursuant to section (8)(c) of the Act, the Attorney General may review the results of the lease sale prior to the acceptance of bids and issuance of leases.

(e) If the authorized officer fails to accept the highest bid for a lease within 60 days after the date on which the bids are opened, all bids for that lease shall be considered rejected.

(f) Written notice of the authorized officer's action shall be transmitted promptly to those bidders whose deposits have been held. If a bid is accepted, such notice shall transmit 3 copies of the lease to the successful bidder. The bidder shall be required, not later than the 15th day after receipt of the lease to execute the lease, pay the first year's rental, pay the balance of the bonus bid, unless deferred, and file a bond as required in § 3318.1 of this title. Deposits and any interest due shall be refunded on rejected bids.

(g) If the successful bidder fails to execute the lease within the prescribed time or otherwise comply with the applicable regulations the deposit shall be forfeited and disposed of as other receipts under the act.

(h) If, before the lease is executed on behalf of the United States, the land which would be subject to the lease is withdrawn or restricted from leasing, all deposits and any interest due shall be refunded.

(i) If the awarded lease is executed by an agent acting on behalf of the bidder, the lease shall be accompanied by evidence that the bidder authorized the agent to execute the lease. When three copies of the lease are executed and returned to the authorized officer, the lease shall be executed on behalf of the United States, and one fully executed copy shall be transmitted to the successful bidder.

(j) No lease or permit shall be issued for any area within 15 statute miles of the boundaries of the Point Reyes Wilderness in California unless the State of California allows exploration, development or production activities in the adjacent navigable waters of the State under section 11(h) of the Act.

§ 3316.6 Lease form.

Oil and gas leases and leases for sulphur shall be issued on forms approved by the Director. Other mineral leases shall be issued on such forms and may be prescribed by the Secretary.

§ 3316.7 Dating of leases.

All leases issued under the regulations in this part shall be dated and become effective as of the first day of the month following the date leases are signed on behalf of the lessor. When prior written request is made, a lease may be dated and become effective as of the first day of the month within which it is so signed.

Subpart 3317--Rentals and Royalties

§ 3317.1 Rentals.

(a) Except for leases issued subject to fixed-net profit sharing provisions, an annual rental shall be due and payable in advance, at the rate specified in the oil and gas leases, on the first day of each lease year prior to discovery of oil or gas on the lease.

(b) The owner of any lease created by the segregation of a portion of a producing lease which is not subject to fixed net profit sharing provisions and on which segregated portion there is no production, actual or allocated, shall pay an annual rental for such segregated portion at the rate per acre or hectare specified in the lease. This rental shall be payable each lease year following the year in which the segregation became effective and

prior to a discovery on such segregated portion.

(c) Annual rental paid in any year shall be in addition to, and shall not be credited against, any royalties due from production.

(d) An annual rental on a lease for a mineral other than oil or gas, shall be due and payable, in advance, on the first day of each lease year prior to discovery in paying quantities, at a rate specified in the lease form.

(e) For leases issued subject to the fixed net profit sharing provisions, annual rental payments shall be due and payable in advance, on the first day of each lease year which commences prior to the date the first profit share payment becomes due. The owner of any lease created by the segregation of a portion of a lease subject to fixed net profit sharing provisions, shall pay an annual rental for such segregated portion at the rate per acre or hectare specified in the lease. This rental shall be payable each year following the year in which the segregation becomes effective and shall continue to be due and payable, in advance, on the first day of each year which commences prior to the date the first profit share payment becomes due.

[45 FR 69175, Oct. 17, 1980]

§ 3317.2 Royalties.

(a) Royalties on oil and gas shall be at the rate specified in the lease, unless the Secretary, in order to promote increased production on the leased area through direct, secondary or tertiary recovery means, reduces or eliminates any royalty set forth in the lease.

(b) The royalty on sulphur shall be not less than 5 percent of the gross production or value of the sulphur at the wellhead.

§ 3317.3 Minimum royalty.

For leases which provide for minimumum royalty payments, each lessee shall pay the minimum royalty specified in the lease at the end of each lease year beginning with the first lease year following a discovery on the lease.

§ 3317.4 Effect of suspensions on royalty and rental.

(a) If under the provisions of 30 CFR 250.12 (c), (d)(1), or (d)(4), the Director, Geological Survey, with respect to any lease, directs the suspension of both operations and production, or, with respect to a lease on which there is no producible well, directs the suspension of of operations, no payment of rental or minimum royalty shall be required for or during the period of suspension.

(b) The lessee shall not be relieved of the obligation to pay rental, minimum royalty or royalty for or during the period of suspension if the Director, Geological Survey: (1) under the provisions of 30 CFR 250.12(d)(1) approves, at the request of a lessee, the suspension of operations or production, or both, or (2) under the provisions of 30 CFR 250.12(d)(3) suspends any operation, including production.

(c) If the lease anniversary date falls within a period of suspension for which no rental or minimum royalty payments are required under paragraph (a) of this action, the prorated rentals or minimum royalties are due and payable as of the date the suspension period terminates. These amounts shall be computed and notice thereof given the lessee. The lessee shall pay the amount due within 30 days after receipt of such notice. The anniversary date of a lease shall not change by reason of any period of lease suspension or rental or royalty relief resulting therefrom.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

Subpart 3318--Bonding

§ 3318.1 Acceptable bonds.

(a) The successful bidder, prior to the issuance of an oil and gas or sulphur lease, shall furnish the authorized officer a corporate surety bond in the sum of $50,000 conditioned on compliance with all the terms and conditions of the lease. Such bond shall not be required if the bidder already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of oil and gas and sulphur leases held by the bidder on the OCS for the area in which the lease to be issued is situated.

(b) For the purposes of this section, there are four areas: (1) The Gulf of Mexico; (2) the area offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii; (3) the area offshore the coast of Alaska; and (4) the area offshore the Atlantic Coast.

(c) A separate bond shall be required for each area. An operator's bond in the same amount may be substituted at any time for the lessee's bonds.

(d) The amount of bond coverage on leases for other minerals shall be determined by the Director at the time of the offer to lease and shall be stated in the notice of lease sale.

(e) If, as a result of a default, the surety on a Mineral Lease Bond makes payment to the United States of any indebtedness under a lease secured by the bond, the face amount of such bond and the surety's liability shall be reduced by the amount of such payment.

(f) A new bond in the amount of $300,000 shall be posted within 6 months or such shorter period as the authorized officer may direct after a default. In lieu of the $300,000 bond required in this paragraph, a separate bond for

each lease may be filed within the time period authorized. Failure to post a new bond shall, at the discretion of the authorized officer, be the basis of cancellation of all leases covered by the defaulted bond, except to the extent a separate bond in lieu of the $300,000 bond required by this paragraph has been filed within the time authorized.

§ 3318.2 Form of bond.

All bonds furnished by a lessee or operator shall be on a form approved by the Director.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

§ 3318.3 Additional bonds.

The authorized officer may require additional security in the form of a supplemental bond or bonds or to increase the coverage of an existing bond if, after operations or production have begun, such additional security is deemed necessary.

Subpart 3319—Assignments, Transfers, and Extensions

§ 3319.1 Assignment of leases or interests therein.

(a) Subject to the approval of the authorized officer, leases, or any undivided interest therein, may be assigned in whole, or as to any officially designated subdivision, to anyone qualified under § 3316.1(b) of this title to hold a lease.

(b) An assignment shall be void if it is made pursuant to any prelease agreement described in § 3316.3-4(c) of this title that would cause a bid to be disqualified.

(c) Any approved assignment shall be deemed to be effective on the first day of the lease month following its filing in the appropriate office of the Bureau, unless at the request of the parties, an earlier date is specified in the approval.

(d) The assignor shall be liable for all obligations under the lease accruing prior to the approval of the assignment.

(e) The assignee shall be liable for all obligations under the lease subsequent to the effective date of an assignment, and shall comply with all regulations issued under the Act.

§ 3319.2 Requirements for filing of transfers.

(a)(1) All instruments of transfer of a lease or of an interest therein as to any officially designated subdivision, including operating rights, subleases and assignments of record interest, shall be filed in triplicate for approval within 90 days from the date of final execution. They shall include a statement over the transferee's own signature with respect to citizenship and qualifications similar to that required of a lessee and shall contain all of the terms and conditions agreed upon by the parties thereto. Carried working interests, overriding royalty interests or payments out of production may be created or transferred without requirement for filing or approval.

(2) An application for approval of any instrument required to be filed shall not be accepted unless accompanied by a nonrefundable fee of $25. Any document not required to be filed by these regulations but submitted for record purposes shall be accompanied by a nonrefundable fee of $25 per lease affected. Such documents may be rejected at the discretion of the authorized officer.

(b) An attorney in fact, in behalf of the holder of a lease, operating rights or sublease, shall furnish evidence of authority to execute the assignment or application for approval and the statement required by § 3316.4 of this title.

(c) Where an assignment creates a segregated lease, a bond shall be furnished in the amount prescribed in § 3318.1 of this title. Where an assignment does not create separate leases, the assignee, if the assignment so provides and the surety consents, may become a joint principal on the bond with the assignor.

(d) An heir or devisee of a deceased holder of a lease, or any interest therein, shall be recognized as the lawful successor to such lease or interest, if evidence of status as an heir or devisee is furnished in the form of: (1) a certified copy of an appropriate order or decree of the court having jurisdiction of the distribution of the estate or, (2) if no court action is necessary, the statements of two disinterested parties having knowledge of the facts or a certified copy of the will.

(e) In addition to the requirements of paragraph (d) of this section, the heirs or devisees shall file statements that they are the persons named as successors to the estate with evidence of their qualifications as provided in § 3316.4 of this title.

(f) In the event an heir or devisee is unable to qualify to hold the lease or interest, the heir or devisee shall be recognized as the lawful successor of the deceased and be entitled to hold the lease for a period of not to exceed 2 years from the date of death of the predecessor in interest.

(g) Each obligation under any lease and under the regulations in this part shall inure to the heirs, executors, administrators, successors, or assignees of the lessee.

(h) Where the proposed assignment or transfer is by a person who, at the time of acquisition of an interest in the lease, was on the List of Restricted Joint Bidders, and that assignment

or transfer is of less than the entire interest of the assignor or transferor, to a person or persons on the same List of Restricted Joint Bidders, the assignor or transferor shall file a copy, prior to approval of the assignment, of all agreements applicable to the acquisition of that lease or a fractional interest.

§ 3319.3 Attorney General review.

Prior to the approval of an assignment or transfer, the Secretary shall consult with and give due consideration to the views of the Attorney General. The Secretary may act on an assignment or transfer if the Attorney General has not responded to the request for consultation within 30 days of said request.

§ 3319.4 Separate filings for assignments.

A separate instrument of assignment shall be filed for each lease. When transfers to the same person, association or corporation, involving more than one lease are filed at the same time for approval, one request for approval and one showing as to the qualifications of the assignee shall be sufficient.

§ 3319.5 Effect of assignment of a particular tract.

(a) When an assignment is made of all the record title to a portion of the acreage in a lease, the assigned and retained portions become segregated into separate and distinct leases. In such a case, the assignee becomes a lessee of the Government as to the segregated tract that is the subject of assignment, and is bound by the terms of the lease as though the lease had been obtained from the United States in the assignee's own name, and the assignment, after its approval, shall be the basis of a new record. Royalty, minimum royalty and rental provisions of the original lease shall apply separately to each segregated portion.

(b) For assignments of a portion of an oil and gas lease approved after the effective date of this section, each segregated lease shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil or gas is produced from that segregated portion of the leased area in paying quantities or drilling or well reworking operations as approved by the Secretary are conducted.

(c) For those assignments approved prior to the effective date of this section, each segregated lease shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil and gas may be produced from the original leased area in paying quantities or drilling or well reworking operations, as approved by the Secretary, are conducted.

§ 3319.6 Extension of lease by drilling or well reworking operations.

The term of a lease shall be extended beyond the primary term so long as drilling or well reworking operations are approved by the Secretary according to the conditions set forth in 30 CFR 250.35.

§ 3319.7 Directional drilling.

In accordance with an approved exploration plan or development and production plan, a lease may be maintained in force by directional wells drilled under the leased area from surface locations on adjacent or adjoining land not covered by the lease. In such circumstances, drilling shall be considered to have commenced on the leased area when drilling is commenced on the adjacent or adjoining land for the purpose of directional drilling under the leased area through any directional well surfaced on adjacent or adjoining land. Production, drilling or reworking of any such directional well shall be considered production or drilling or reworking operations on the leased area for all purposes of the lease.

§ 3319.8 Compensatory payments as production.

If an oil and gas lessee makes compensatory payments as provided in 30 CFR 250.33 and if the lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of the lease.

§ 3319.9 Effect of suspensions on lease term.

(a) If the Director, Geological Survey, directs the suspension of either operations or production, or both, under the provisions of 30 CFR 250.12(c), (d)(1) or (d)(4) with respect to any lease in its primary term, the primary term of the lease shall be extended by a period equivalent to the period of the suspension.

(b) If the Director, Geological Survey, orders or approves the suspension of either operations or production, or both, under the provision for 30 CFR 250.12(c), (d)(1), or (d)(4) with respect to any lease extended beyond its primary term, the term of the lease shall not be deemed to expire so long as that suspension remains in effect.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

Subpart 3320--Termination of Leases

§ 3320.1 Relinquishment of leases or parts of leases.

A lease or any officially designated subdivision thereof may be surrendered by the record title holder by filing a written relinquishment, in triplicate, with the appropriate OCS office of the Bureau. No filing fee is required. A relinquishment shall take effect on the date it is filed subject to the continued obligation of the lessee and the surety to make all payments due, including any accrued rentals, royalties and deferred bonuses and to abandon all wells and condition or remove all platforms and other facilities on the land to be relinquished to the satisfaction of the Director, Geological Survey.

§ 3320.2 Cancellation of leases.

(a) Any nonproducing lease issued under the act may be cancelled by the authorized officer whenever the lessee fails to comply with any provision of the act or lease or applicable regulations, if such failure to comply continues for 30 days after mailing of notice by registered or certified letter to the lease owner at the owner's record post office address. Any such cancellation is subject to judicial review as provided in section 23(b) of the Act.

(b) Producing leases issued under the act may be cancelled by the Secretary whenever the lessee fails to comply with any provision of the act, applicable regulations or the lease only after judicial proceedings as prescribed by section 5(d) of the Act.

(c) Any lease issued under the Act, whether producing or not, shall be canceled by the authorized officer upon proof that it was obtained by fraud or misrepresentation, and after notice and opportunity to be heard has been afforded to the lessee.

(d) Pursuant to section 5(a) of the Act, the Secretary may cancel a lease when: (1) continued activity pursuant to such lease would probably cause serious harm or damage to life, property, any mineral, national security or defense, or to the marine, coastal or human environment;

(2) the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and (3) the advantages of cancellation outweigh the advantages of continuing such lease or permit in force. Procedures and conditions contained in 30 CFR 250.12 shall apply as appropriate.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

Subpart 3321--Section 6 Leases

§ 3321.1 Effect of regulations on lease.

(a) All regulations in this part, insofar as they are applicable, shall superseded the provisions of any lease which is maintained under section 6(a) of the Act. However, the provisions of a lease relating to area, minerals, rentals, royalties (subject to section 6(a)(8) and (9) of the Act, and term (subject to section 6(a)(10) of the Act and, as to sulfur, subject to section 6(b)(2) of the Act) shall continue in effect, and, in the event of any conflict or inconsistency, shall take precedence over these regulations.

(b) A lease maintained under section 6(a) of the Act shall also be subject to all operating and conservation regulations applicable to the OCS. In addition, the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way are applicable, to the extent that those regulations are not contrary to or inconsistent with the lease provisions relating to area, the minerals, rentals, royalties and term. The lessee shall comply with any provision of the lease as validated, the subject matter of which is not covered in the regulations in this part.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

§ 3321.2 Leases of other minerals.

The existence of a lease that meets the requirements of section 6(a) of the Act shall not preclude the issuance of other leases of the same area for deposits of other minerals. However, no other lease of minerals shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the existing lease. No sulphur leases shall be granted by the United States on any area while such area is included in a lease covering sulphur under section 6(b) of the Act.

Subpart 3331--Studies

§ 3331.1 Environmental studies.

(a) The Director shall conduct a study of any area or region included in any lease sale in order to establish information needed for assessment and management of impacts on the human, marine and coastal environments which may be affected by OCS oil and gas activities in such area or region. Any study shall, to the extent practicable, be designed to predict environmental impacts of pollutants introduced into the environments and of the impacts of offshore activities on the seabed and affected coastal areas.

(b) Studies shall be planned and carried out

in cooperation with the affected States and interested parties and, to the extent possible, shall not duplicate studies done under other laws. Where appropriate, the Director shall, to the maximum extent practicable, enter into agreements with the National Oceanic and Atmospheric Administration in executing the environmental studies responsibilities. By agreement, the Director may also utilize services, personnel or facilities of any Federal, State or local government agency in the conduct of such study.

(c) Any study of an area or region required by paragraph (a) of this section for a lease sale shall be commenced not later than six months prior to holding a lease sale for that area. The Director may utilize information collected in any prior study. The Director may initiate studies for areas or regions not identified in the leasing program.

(d) After the leasing and developing of any area or region, the Director shall conduct such studies as are deemed necessary to establish additional information and shall monitor the human, marine and coastal environments of such area or region in a manner designed to provide information which can be compared with the results of studies conducted prior to OCS oil and gas development. This shall be done to identify any significant changes in the quality and productivity of such environments, to establish trends in the areas studies, and to design experiments identifying the causes of such changes. Findings from such studies shall be used to recommend modifications in practices which are employed to mitigate the effects of OCS activities and to enhance the data/information base for predicting impacts which might result from a single lease sale or cumulative OCS activities.

(e) Information available or collected by the studies program shall, to the extent practicable, be provided in a form and in a timeframe that can be used in the decisionmaking process associated with a specific leasing action or with longer term OCS minerals management responsibilities.

Subpart 3340—Grants of Pipeline Rights-of-way on the Outer Continental Shelf

§ 3340.0-1 Purpose.

(a) The purpose of these regulations is to provide the procedure for the granting and administering of rights-of-way for the transportation of minerals by pipeline through the OCS.

(b) Compliance with the regulations of this subpart does not supersede the requirements of complying with the regulations of the Department of Transportation, the Department of the Army and the Federal Energy Regulatory Commission.

§ 3340.0-2 Policy.

The respective Bureau of Land Management OCS offices shall, as appropriate, engage in transportation planning in advance of receipt of an application for a right-of-way. The intergovernmental planning program or similar process shall be used to involve relevant parties in this advanced planning.

The construction of gathering lines may be approved by the Director, Geological Survey, in accordance with the provisions of 30 CFR 250.18 and 250.68.

§ 3340.0-5 Definitions.

As used in this subpart, the term "right-of-way" includes the site on which the pipeline and associated structures are situated which shall not exceed 200 feet in width for pipelines unless safety and environmental factors during construction and operations require a greater width and shall be limited to the area reasonably necessary for pumping stations or other accessory structures. It does not include gathering lines and associated structures constructed for the purpose of conveying production for gathering, storage or treating of the production from a lease or leases.

§ 3340.1 Nature of grant.

(a) An applicant, by accepting a right-of-way grant, agrees and consents to comply with the requirements set out below.

(1) The holder shall comply with all existing regulations and with all existing and future regulations which the Secretary determines to be necessary and proper in order to provide for the prevention of waste, the conservation of the natural resources of the OCS and the protection of correlative rights therein. The holder shall comply with all stipulations which the authorized officer attaches to the right-of-way grant for the purpose of assuring maximum environmental protection. The holder shall utilize the best available and safest technologies, such as the safest reasonable pipeline burial techniques, which the Secretary determines to be economically feasible.

(2) The holder shall pay the United States or its lessees or right-of-way holders, as the case may be, the full value for all damages to the property of the United States or its said lessees or right-of-way holders, and shall indemnify the United States against any and all liability for damages to life, person or property arising from the occupation and use of the area covered by the right-of-way grant.

(3) The authorized officer shall be kept informed at all times of the holder's address, and, if a corporation, of the address of its principal place of business and the name and address of the officer or agent authorized to re-

ceive service of notice. In the construction, operation and maintenance of the pipeline, the holder shall not discriminate against any employee or applicant for employment because of race, creed, color, sex or national origin and shall require an identical provision in all subcontracts.

(4) The granting of the right-of-way shall be subject to the express conditions that the rights granted shall not prevent or interfere in any way with the management, administration of, or the granting, either prior or subsequent to the right-of-way grant, of other rights by the United States. Moreover, the holder agrees to allow the occupancy and use by the United States, its lessees or other rights-of-way holders of any part of the right-of-way grant not actually occupied or necessarily incident to its use for any necessary operations involved in the management, administration or the enjoyment of such other granted rights.

(5) For the first calendar year or fraction thereof, and therafter annually, the holder shall pay the Bureau, in advance, an annual rental of $15 for each statute mile or fraction thereof, traversed by the right-of-way and $75 for each area applied for as a site for an accessory to the right-of-way, including, but not limited, to a platform. Payments may be on an annual basis, for a 5-year period or for multiples of the 5-year period.

(6) Upon abandonment, relinquishment, revocation or termination of the right-of-way grant, the holder shall remove any platforms, structures, domes over valves, the pipe, taps and valves along the right-of-way which would present any hazard to navigation or fishing, unless this requirement is waived in writing by the authorized officer. In order to secure a waiver, the holder shall demonstrate to the satisfaction of the authorized officer that any abandonment in place shall not constitute an unreasonable hazard to navigation, fishing or the marine environment, and the line has been purged to remove materials that, if released, could be harmful to the marine environment. The holder shall also demonstrate to the satisfaction of the authorized officer that all open ends of the pipe have been plugged and buried to a minumum cover of three feet or such other depth as may be required by the authorized officer.

Any improvement required to be removed shall be removed by the holder within one year of the effective date of the relinquishment, revocation, termination or abandonment. All such structure, accessories thereto, or improvements not removed within the time provided herein, shall become the property of the United States but that shall not relieve the holder of liability for the cost of their removal or for restoration of the site. Any application for relinquishment of a right-of-way shall be filed in accordance with § 3340.5 of this title.

(7) The holder shall suspend operations of any pipeline for a period of time specified by the authorized officer upon a determination by the authorized officer that continued operation would threaten or result in serious, irreparable, or immediate harm to life (including fish and other aquatic life), to property, to mineral deposits or the marine, coastal or human environments. The authorized officer may, to aid in the determination, request and consider the views and recommendations of appropriate Federal and State agencies. The authorized officer may also suspend operations if the holder fails to comply with applicable law, regulations or terms of the grant. The Secretary may cancel a grant under section 5(a)(2) of the Act.

(8) The holder shall operate and maintain the pipeline in such a manner so as not to pose an unreasonable obstruction to fishing and shipping operations.

(9) The holder shall furnish the authorized officer, within 30 days of request, all data as to maximum design capacity of the pipeline, average product quantity being moved as of the time of request and copies of all contracts for transportation existing at the time of request.

(10) The holder shall assure that such oil or gas pipelines, shall, at the option of the Federal Energy Regulatory Commission, either transport or purchase oil or natural gas produced from submerged lands in the vicinity of the pipeline without discrimination and in such proportionate amounts as the Federal Energy Regulation Commission, may, after a full hearing with due notice thereof to the interested parties, determine to be reasonable, taking into account, among other things, conservation and the prevention of waste.

(11) Unless otherwise exempted by the Federal Energy Regulatory Commission pursuant to section 5(f)(2) of the Act, the holder shall provide open and nondiscriminatory access to the pipelines to both owner and nonowner shippers.

(12) The holder shall comply with the provisions of section 5(f)(1)(B) of the Act, under which the Federal Energy Regulatory Commission may order an expansion of the throughput capacity of a pipeline which is authorized after September 18, 1978, and which is not located in the Gulf of Mexico or the Santa Barbara Channel.

(b) Failure to comply with the Act, regulations or any conditions prescribed by the Secretary as to the right-of-way and the survey, location and width of a pipeline shall be grounds for forfeiture of the grant in an appropriate judicial proceeding instituted by the United States in any United States District Court having jurisdiction under the provisions of section 23 of the Act.

(c) Any right-of-way granted under the provisions of this subpart shall be for so long as the pipeline is properly maintained and used

for the purpose for which the grant was made, unless otherwise expressly stated in the grant. Temporary cessation or suspension shall not terminate the grant. Where pipeline segments become corroded or otherwise worn and need replacement, proper maintenance may be performed under a temporary cessation of use. If the purpose of the grant ceases to exist or use of the pipeline is permanently discontinued for any reason, the grant shall be subject to forfeiture.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26,1979; 45 FR 69175, Oct. 17, 1980]

§ 3340.2 Application procedures.

§ 3340.2-1 Applications.

(a) No special form of application is required. The application shall be filed in triplicate in the OCS office having jurisdiction of the lands covered by the application. It shall specify that it is made pursuant to the act and these regulations and that the applicant agrees that if the right-of-way grant is approved, the grant shall be subject to the terms and conditions of the regulations in this part. It shall also state the primary purpose for which the right-of-way is to be used. If the right-of-way has been utilized prior to the time the application is made, the application shall state the date such utilization commenced and by whom, and the date applicant obtained control of the improvement. A nonrefundable filing fee of $100 and the rental required herein under § 3340.1(a)(5) of this title, shall accompany the application. A separate application shall be filed for each right-of-way.

(b) Each coppy of the application shall be accompanied by a map, showing the center line of the right-of-way, properly identified so that the right-of-way can be accurately located by a competent engineer. The map shall comply with the following requirements:

(1) The scale shall be at least 1":4,000', or such other scale as may be determined by the authorized officer.

(2) Distances of the center line of the right-of-way and grid references for all turning points shall be given either on the margin of the map or on an attached sheet or sheets with the courses referred to the true or grid meridian, either by deflection from a line of known bearing or by independent observation and calculated distances in feet and decimals.

(3) The total distance and width of the right-of-way shall be given, and the diameter of the pipeline specified.

(4) The initial and terminal points of the right-of-way and any continuation into State jurisdiction shall be accurately located by grid references, even though the right-of-way may have an onshore terminal point.

(5) Each copy of the map shall bear upon its face a signed certificate of the engineer who made the map that the right-of-way is accurately represented upon the map, and the design characteristics are in accordance with Department of Transportation regulations.

(c) Rights-of-way issued pursuant to section 5(e) of the act may be acquired or held only by citizens and nationals of the United States, aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. § 1101(a)(20), private, public or municipal corporations organized under the laws of the United States, the District of Columbia, or of any State, or territory thereof, or associations of such citizens, nationals, resident aliens or private, public or municipal corporations, States or political subdivisions of States.

(d)(1) An individual applicant shall submit with the application a statement of citizenship or nationality. An applicant who is an alien lawfully admitted for permanent residence in the United Staes shall also submit with the application evidence of such status.

(2) If the applicant is an association (including a partnership), the application shall also be accompanied by a certified copy of the articles of association or appropriate reference to the record of the Bureau in which such a copy has already been filed, with a statement as to any subsequent amendments.

(3) If the applicant is a corporation, the following additional information shall be submitted with the application:

(i) A statement certified by the secretary or assistant secretary of the corporation with the corporate seal, showing the state in which it is incorporated and the name of the person(s) authorized to act on behalf of the corporation, or

(ii) In lieu of such a statement, an appropriate reference to statements or records previously submitted to the Bureau (including material submitted in compliance with prior regulations).

(e)(1) An applicant shall show the extent to which the right-of-way applied for invades or crosses mineral leases, rights-of-way or Geological Survey easements other than the applicant's own. The application shall contain a statement that a copy of the application has been delivered personally or by registered or certified mail to each lessee or right-of-way or easement holder whose lease, right-of-way, or easement is so affected. When the statement is filed, no final action shall be taken on the right-of-way grant application until 30 days have elapsed after the date of service of such papers, in order to afford the parties concerned ample opportunity to comment on the granting of the right-of-way. A copy of the comments shall be filed with the authorized officer for his consideration.

(2) If the authorized officer determines that

a change in the application as filed should be made based on the comments received, the authorized officer shall notify the applicant that an amended application shall be filed subject to changes which the authorized officer stipulates. The authorized officer shall determine whether the applicant shall deliver copies of the amended application to other parties for comment pursuant to § 3340.2-1(e)(1) of this title.

[44 FR 38276, June 29, 1979; 45 FR 55380, Sept. 26, 1979]

§ 3340.2-2 Approval action.

(a) In considering the application for a right-of-way, the authorized officer shall consider the potential effect of the pipeline on the human, marine and coastal environments, life, including aquatic life, property and mineral resources in the entire area during construction and operational phases. The authorized officer shall prepare an environmental analysis in accordance with applicable policies and guidelines. To aid in the evaluation and determinations, the authorized officer may request and consider views and recommendations of appropriate Federal agencies, may hold public meetings after appropriate notice, and may consult, as appropriate, with State agencies, organizations, industries and individuals. The authorized officer shall attach, as a condition to approval, special stipulations and conditions necessary to protect human, marine and coastal environments, life, including aquatic life, property and mineral resources, located on or adjacent to the proposed right-of-way. In approving the pipeline right-of-way, consideration shall be given to any recommendation of the intergovernmental planning program, or similar process, for the assessment and management of OCS oil and gas transportation.

(b) If the right-of-way as applied for crosses any area withdrawn from disposal or restricted from oil and gas activities, it shall be rejected unless the Federal agency in charge of such withdrawn or restricted area gives its consent to the granting of the right-of-way. In such case the applicant, upon request filed within 30 days after receipt of the rejection notice, shall be allowed an opportunity to file an amended application rerouting the proposed right-of-way so as to eliminate the conflict.

(c) Should the proposed route of the right-of-way adjoin and subsequently cross any State submerged lands, the applicant shall submit to the authorized officer evidence that the State or States so affected have reviewed the application, and shall submit any comment received, including any recommendations to relocate the route, if such relocation is considered necessary. In the event of a State recommendation to relocate the proposed route, the authorized officer shall coordinate with the appropriate State officials all applications for right-of-way grants that pass from Federal to State submerged lands.

(d) If an application is for a grant for a right-of-way affecting any land or water use in the coastal zone of any State with a coastal zone management program approved under section 306 of the Coastal Zone Management Act of 1972 (16 U.S.C. 1455), then the application shall not be approved unless it is consistent with the approved coastal zone management program or until the Secretary of Commerce makes a finding that the right-of-way will be consistent with the objectives or purposes of the Coastal Zone Management Act of 1972, or is necessary in the interest of national security. However, if the application is for a grant for a right-of-way that has been described in detail in an approved development and production plan, then the application may be approved without a further finding of consistency with any approved coastal zone management progam or a further finding on the part of the Secretary of Commerce. (See 30 CFR 250.34-2.)

(e) If the application and other required information are found to be in compliance with applicable law and regulations, the right-of-way may be granted. If the application is rejected, the decision shall be in writing and shall state the reasons for the decision.

§ 3340.3 Construction.

(a) Failure to construct the pipeline within years from the date of the grant shall be deemed to be an abandonment of the grant and deemed to be a forfeiture. Proof of construction shall be submitted to the authorized officer within 90 days after completion of construction of the pipeline. Such proof shall consist of drawings of the pipeline as built, in triplicate; a signed certificate by the engineer that the pipeline is accurately represented; grid references for all turning points on the line; and other data as required by the authorized officer. If there is a substantial deviation from the right-of-way as shown on the original map, the unused portion of the grant shall be relinquished and maps, in triplicate, of the location of the right-of-way as constructed shall be be furnished to the authorized officer as soon as possible after the deviation is determined to be necessary or advisable. Any deviation made prior to approval of such supplemental plat shall be at the risk of the holder.

(b) Right-of-way grants shall be reviewed annually prior to commencement of construction of any pipeline. Any significant change in conditions subsequent to the granting of a right-of-way but prior to commencement of construction may be grounds for a request to alter the grant by the authorized officer. The authorized officer shall give consideration to any

recommendation of the intergovernmental planning program or similar process.

§ 3340.4 Assignment of right-of-way.

(a) Assignment may be made of a right-of-way grant in whole or of any lineal segment thereof, subject to the approval of the authorized officer. Any such proposed assignment shall be filed in triplicate, accompanied by an application for approval in which the assignee shall make the showing required by § 3340.2-1(c) of this title and agree to the terms and conditions prescribed in § 3340.1(a) of this title.

(b) Any proposed assignment, in whole or in part of any right, title or interest in a right-of-way grant, shall be accompanied by the same showing of qualifications of the assignees as is required of an applicant, and shall be supported by a stipulation that the assignee agrees to comply with and to be bound by the terms and conditions of the right-of-way grant. No transfer shall be recognized unless and until it is first approved in writing by the authorized officer. A nonrefundable fee of $25 shall accompany the application for the approval of an assignment.

§ 3340.5 Relinquishment of right-of-way.

A right-of-way grant or a portion thereof may be surrendered by the record holder by filing a written relinquishment, in triplicate, with the authorized officer. A relinquishment shall take effect on the date it is filed subject to the satisfation of all requirements for abandonment in § 3340.1(a)(6) of this title.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979]

§ 3340.6 Change of use or flow.

(a) A change may be made by the holder in the use of the pipeline or direction of flow from that specified in the approved permit only if prior approval is obtained from the Department of Transportation and the authorized officer. Application for such a change shall be filed not less than 15 working days in advance of the proposed change of use or flow.

(b) Each application shall specify whether the change is to be temporary or permanent, and any technical changes necessary to accommodate the change.

(c) Each application shall demonstrate that the pipeline is physically and technically adaptable to the proposed change without adverse environmental effects.

§ 3340.7 Bonding.

(a) Prior to the issuance of a right-of-way grant the applicant shall furnish the authorized officer a corporate surety bond in the sum of $300,000 conditioned on compliance with all the terms of the grant. A similar bond shall be furnished for all previously issued rights-of-way within 90 days of the effective date of this section. Such bond shall not be required if the applicant already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of all right-of-way grants held by the applicant on the OCS for the area in which the grant to be issued is situated. This bond shall be in addition to any bond required of a lessee in subpart 3318 of this title.

(b) For the purposes of this section, there are four areas: (1) the Gulf of Mexico; (2) the area offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii; (3) the area offshore the Coast of Alaska; and (4) the area offshore the Atlantic Coast.

(c) A separate bond shall be required for each area.

(d) If, as the result of a default, the surety on a right-of-way grant bond makes payment to the Government of any indebtedness under a grant secured by the bond, the face amount of such bond and the surety's liability shall be reduced by the amount of such payment.

(e) A new bond in the amount of $300,000 shall be posted within 6 months or such shorter period as the authorized officer may direct after a default. Failure to post a new bond shall, at the discretion of the authorized officer, be the basis of cancellation of all grants covered by the defaulted bond.

Appendix A

Suggested Bid Form. It is suggested that bidders submit their bids to the Manager, Outer Continental Shelf Office, in the following form:

Oil and Gas Bid

The following bid is submitted for an oil and gas lease on the tract of the Outer Continental Shelf specified below:

Tract No. __________
Total amount bid __________
Amount per acre/hectare __________
Amount of cash bonus submitted with bid __________

Proportionate Interest of Company(ies) Submitting Bid

Qualification No. __________
Company __________
Percent interest __________
Address __________
Signature __________ (Please type signer's name under signature)

Appendix B

Required Joint Bidder's Statement. In the case of joint bids, each joint bidder is required to execute a joint bidder's statement before a notary public and submit it with his bid. A suggested form for this statement is shown below:

Joint Bidder's Statement

I hereby certify that ____________________ (entity submitting bid) is eligible under 43 CFR 3316.3 to bid jointly with the other parties submitting this bid.

____
Signature (Please type signer's name under signature.)

Sworn to and subscribed before me this ______ day of ______________ 19________.

Notary Public
State of ______________________________
County of ______________________________

III. OUTER CONTINENTAL SHELF OFFICES

U.S. GEOLOGICAL SURVEY

Headquarters
Conservation Division
U.S. Geological Survey
National Center (MS 600)
Reston, Virginia 22092
Commercial 703-860-7581
FTS 8-928-7581

Alaska Region
Conservation Division
U.S. Geological Survey
800 A Street, Suite 201
Anchorage, Alaska 99501
Commercial 907-271-4301
FTS 8-399-0150 (Seattle)

Atlantic OCS Region
Conservation Division
U.S. Geological Survey
1725 K Street NW, Suite 204
Washington, D.C. 20006
Commercial 202-254-3137
FTS 8-254-3137

Gulf of Mexico OCS Region
Conservation Division
U.S. Geological Survey
3301 North Causeway Blvd.
P.O. Box 7944
Metairie, Louisiana 70010
Commercial 504-837-4720
FTS 8-680-9381

Pacific Region
Conservation Division
U.S. Geological Survey
1340 West 6th Street, Room 160
Los Angeles, California 90017
Commercial 213-688-2846
FTS 8-798-2846

BUREAU OF LAND MANAGEMENT

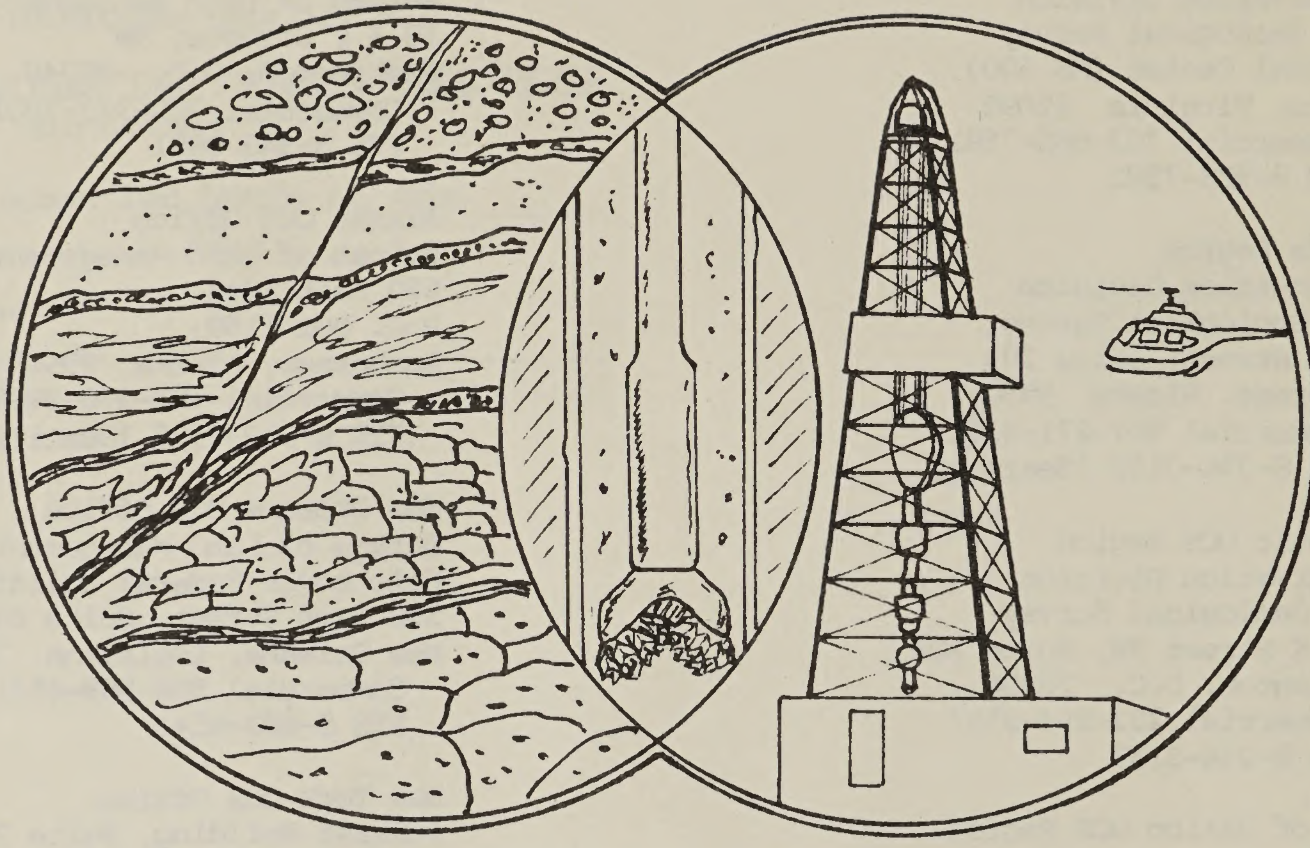
Headquarters
Bureau of Land Management
18 & C Streets, NW
Washington, D.C. 20240
Commercial 202-343-3801
FTS 8-343-3801

Alaska OCS Office
Bureau of Land Management
620 East 10th
P.O. Box 1159
Anchorage, Alaska 99510
Commercial 907-276-2955
FTS 8-399-0150 (Seattle)

New Orleans OCS Office
Bureau of Land Management
Hale Boggs Federal Building
500 Camp Street, Suite 841
New Orleans, Louisiana 70130
Commercial 504-589-6541
FTS 8-682-6541

New York OCS Office
Federal Building, Suite 32-120
26 Federal Plaza
New York, New York 10278
Commercial 212-264-2960
FTS 8-264-2960

Pacific OCS Office
1340 West 6th Street, Room 200
Los Angeles, California 90017
Commercial 213-688-7234
FTS 8-798-7234



NATIONAL TECHNICAL INFORMATION SERVICE
SPECIAL ORDER FORM

NAME ______________________________

ORGANIZATION ______________________________

ADDRESS ______________________________

METHOD OF PAYMENT

Enclosed:

☐ Check ☐ Money Order ☐ American Express; Card Number: ____________

☐ Master Card; Card Number: ____________

☐ VISA; Card Number: ____________

Charge my Deposit Account Number: ____________

Charge Card Expiration Date: ____________ Signature: ____________
Required on all charge card orders

MAKE CHECK AND MONEY ORDERS PAYABLE TO NTIS

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PB81-151540	Compilation of Regulations Related to Mineral Resource Activities on the Outer Continental Shelf, Volumes I & II	

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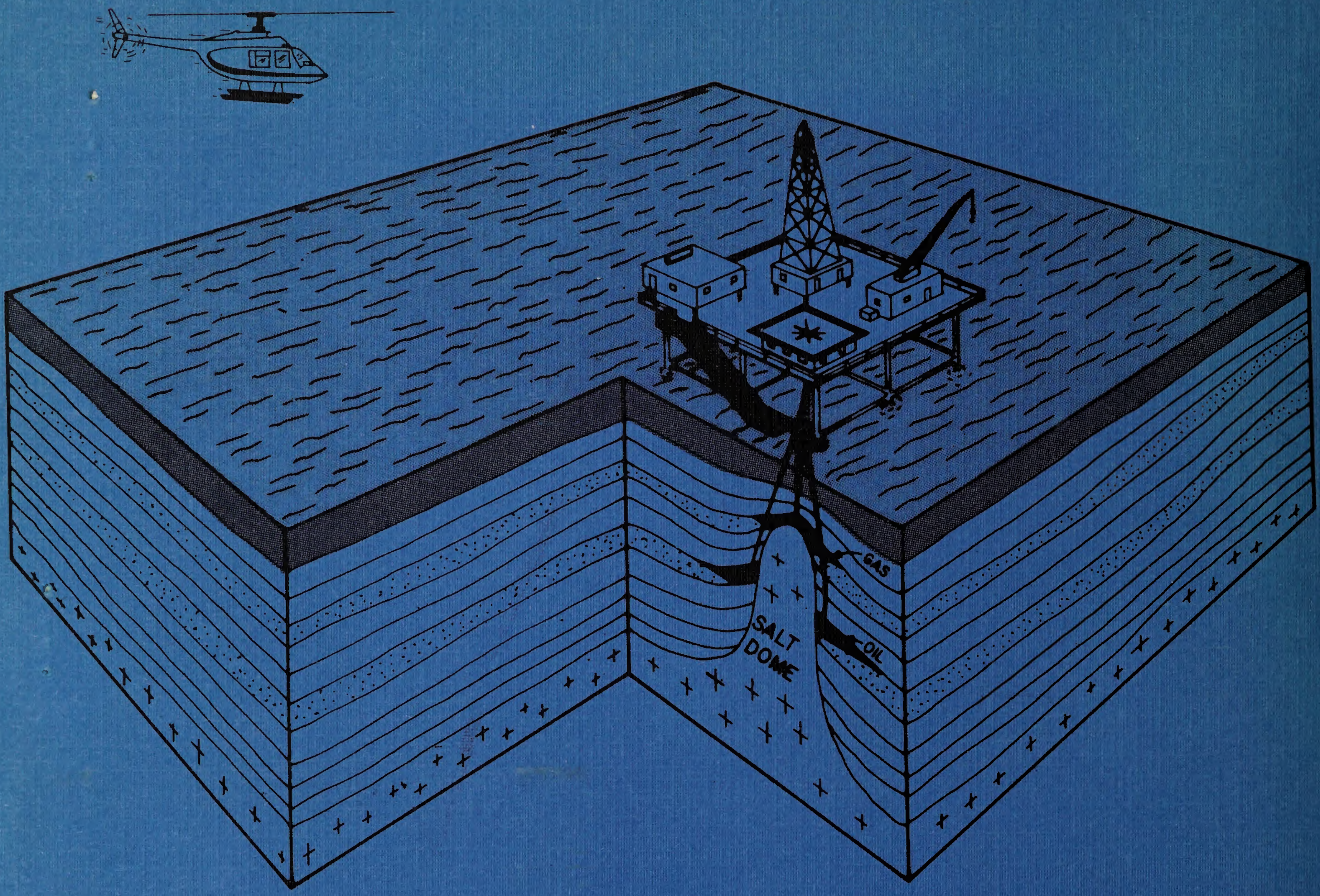

USGS OCS BLM